Offshore Wind Power Limited

West of Orkney Windfarm Offshore EIA Report

Volume 1, Chapter 5 - Project Description

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5 PROJECT DESCRIPTION

5.1 Introduction

This chapter describes the design details of the offshore Project, comprising all offshore components seaward of Mean High-Water Springs (MHWS) (Wind Turbine Generators (WTGs), cables, foundations, Offshore Substation Platforms (OSPs) and all other associated infrastructure) and permanent and temporary works associated with the offshore Project stages from pre-construction and construction through to decommissioning. The design options and parameters of the offshore Project are described herein, alongside the activities and timing for the pre-construction, construction, operation and maintenance, and decommissioning of the offshore Project.

The contractors for the supply and installation of the components of the offshore Project have not yet been identified at the time of this consent application. However, the parameters and methods of construction will be within the Project Design Envelope described within this chapter.

For completeness, a high-level description of the onshore Project is provided in section 5.14 to provide a complete overview of the Project.

5.2 Design envelope approach

The offshore Project has utilised a Project Design Envelope approach to inform this Offshore Environmental Impact Assessment (EIA) Report. The Project Design Envelope approach enables a range of parameter values to be presented for each offshore Project aspect, providing the flexibility to allow for further refinement of the offshore Project design.

The first version of the Project Design Envelope was presented within the EIA Scoping Report, submitted to Marine Scotland - Licensing Operations Team (MS-LOT)[1] and The Highland Council (THC) in March 2022[2]. The Project Design Envelope has been further refined based on the results of environmental surveys, technical and engineering studies and discussions with stakeholders and the community, as part of the EIA process. The Project Design Envelope contains a series of design options, including reasoned maximum and minimum parameter values, within which the final design of the offshore Project will sit. In most instances, this chapter refers to the maximum Project Design Envelope parameter values, as these typically represent the worst case scenario for the EIA and assessing maximum impact only avoids an overly complex EIA. Where the minimum values constitute the worst case scenario, these have been described.

The Project Design Envelope approach has been adopted in accordance with the Scottish Government (2022a) Guidance on using the Design Envelope for Applications under Section 36 of the Electricity Act 1989. The guidance outlines that, where flexibility in design parameters is required, the reason for this should be clearly explained and

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[1] *MS-LOT have since been renamed Marine Directorate - Licensing Operations Team (MD-LOT).*

[2] *The Scoping Report was also submitted to the Orkney Islands Council (OIC), as the scoping exercise included consideration of power export to the Flotta Hydrogen Hub, however, this scope is not covered in the Offshore EIA Report and will be subject to separate Marine Licence and onshore planning applications.*

assessments should be undertaken on the parameters likely to result in the maximum adverse effect (i.e. the worst case scenario). In accordance with this guidance, this chapter outlines those parameters where flexibility has been maintained, and the justification for this has been provided either here or in topic-specific chapters.

The Project Design Envelope has been drafted accounting for ongoing dialogue with the supply chain combined with internal engineering to future proof the Project Design Envelope for any currently unknown product evolutions. As Wind Turbine Generators (WTGs) have significantly increased over the past decade, an internal extrapolation of the design evolution has been assessed to help define the upper parameters of the Project Design Envelope. The Project requires to maintain optionality (e.g. rotor sizes) and competition throughout the procurement process with a relatively small market of suppliers with current proven WTG technology. With such a demand on WTG supply for the years of construction of the Project, the Project Design Envelope ensures that all credible suppliers are included, which in return will allow for the Project to develop the lowest Levelised Cost of Energy (LCoE). The key areas where flexibility within the Project Design Envelope has been maintained include:

- WTG model choice - to ensure that the Project can benefit from the most up to date commercially available WTG technology closer to the time of construction. This may influence parameters such as tip height and hub height;
- WTG layout – this will be determined through a design optimisation process conducted post-consent, that will consider aspects that will not be determined until post-consent, such as WTG model choice, spacing arrangements, Project-specific surveys, metocean conditions, and WTG foundation choice etc., alongside environmental constraint considerations and consultation with stakeholders;
- WTG foundation choice – as per WTG model choice, flexibility is required to ensure that the Project can utilise the most appropriate commercially available foundation solution. The final choice will also be informed through detailed design studies, informed by the results of project specific surveys. The final choice will also affect the type and amount of scour protection required;
- Pre-installation work requirements (e.g. bedform clearance[3], boulder clearance and Unexploded Ordnance (UXO) clearance) – these will depend on the results of the pre-construction geophysical surveys, conducted post-consent;
- Construction programme – will depend on the date that a Contract for Difference (CfD) is awarded, contractor and vessel availability, weather conditions and other supply chain or logistical issues;
- Vessel requirements – dependent on the final Project design, the availability of vessels, and the location of the construction and operation and maintenance bases (determined post-consent); and
- Construction and maintenance methodologies – flexibility has been maintained to account for any supply chain logistical issues or opportunities, and to ensure the most feasible and cost-effective methodologies are selected through a competitive procurement process.

The Project Design Envelope parameter values which represent the worst case scenario for the impact assessments have been determined on a case-by-case basis, depending on the receptor and impact being considered, and these are described in each topic-specific EIA chapter. Further detail on the use of the Project Design Envelope approach is provided in chapter 7: EIA methodology.

[3] *Bedforms include sandwave bedforms, bedform fields comprising of sand and gravel, megaripples and rippled scour depressions which are present in different areas across the offshore Project area (see chapter 8: Marine physical and coastal processes for further information).*

5.3 Project overview

5.3.1 Outline description

The offshore Project will comprise of WTGs and all infrastructure required to transmit the power generated by the WTGs to shore. An overview of the key offshore Project components is provided in Figure 5-1. The key offshore components of the offshore Project will include:

- Up to 125 WTGs with fixed-bottom foundations (monopile, piled jacket or suction bucket jacket);
- Up to five High Voltage Alternating Current (HVAC) OSPs;
- Up to 500 kilometres (km) of inter-array cables;
- Up to 150 km of interconnector cables; and
- Up to five offshore export cables to landfalls at Greeny Geo and/or Crosskirk at Caithness, with a total length of up to 320 km (average of 64 km per offshore export cable).

The key Project milestones are likely to be:

- Commencement of onshore construction – 2027;
- Commencement of offshore construction – 2028; and
- First power, earliest date is 2029.

5.3.2 Offshore Project boundary

The offshore Project boundary (Figure 5-2) includes the array area and the offshore Export Cable Corridor (ECC). The array area reflects the Option Agreement Area (OAA) awarded to Offshore Wind Power Limited (OWPL) through the ScotWind Leasing Round and is approximately 28 km from the west coast of Hoy, Orkney and 23 km from the north coast of Scotland.

Therefore, the offshore Project boundary (for consenting purposes)[4] encompasses:

- OAA – where the WTGs and associated foundations and supporting structures, inter-array cables, interconnector cables and the OSPs will be located;
- Offshore ECC – where the offshore export cables will be located; and
- Landfall (up to MHWS) – where the offshore export cables come ashore and interface with the onshore Project.

[4] *Not reflective of contractual boundaries or interfaces between Project contracts.*

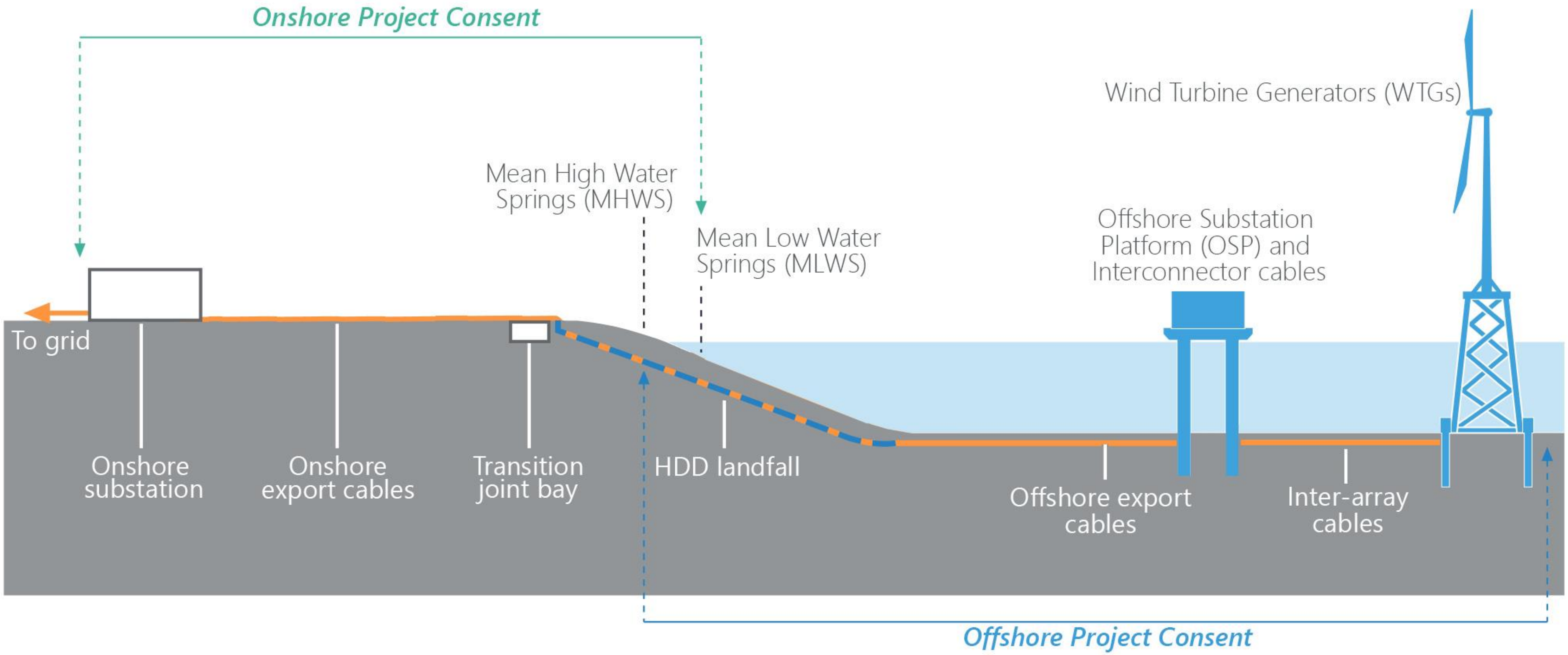

Figure 5-1 Offshore Project overview

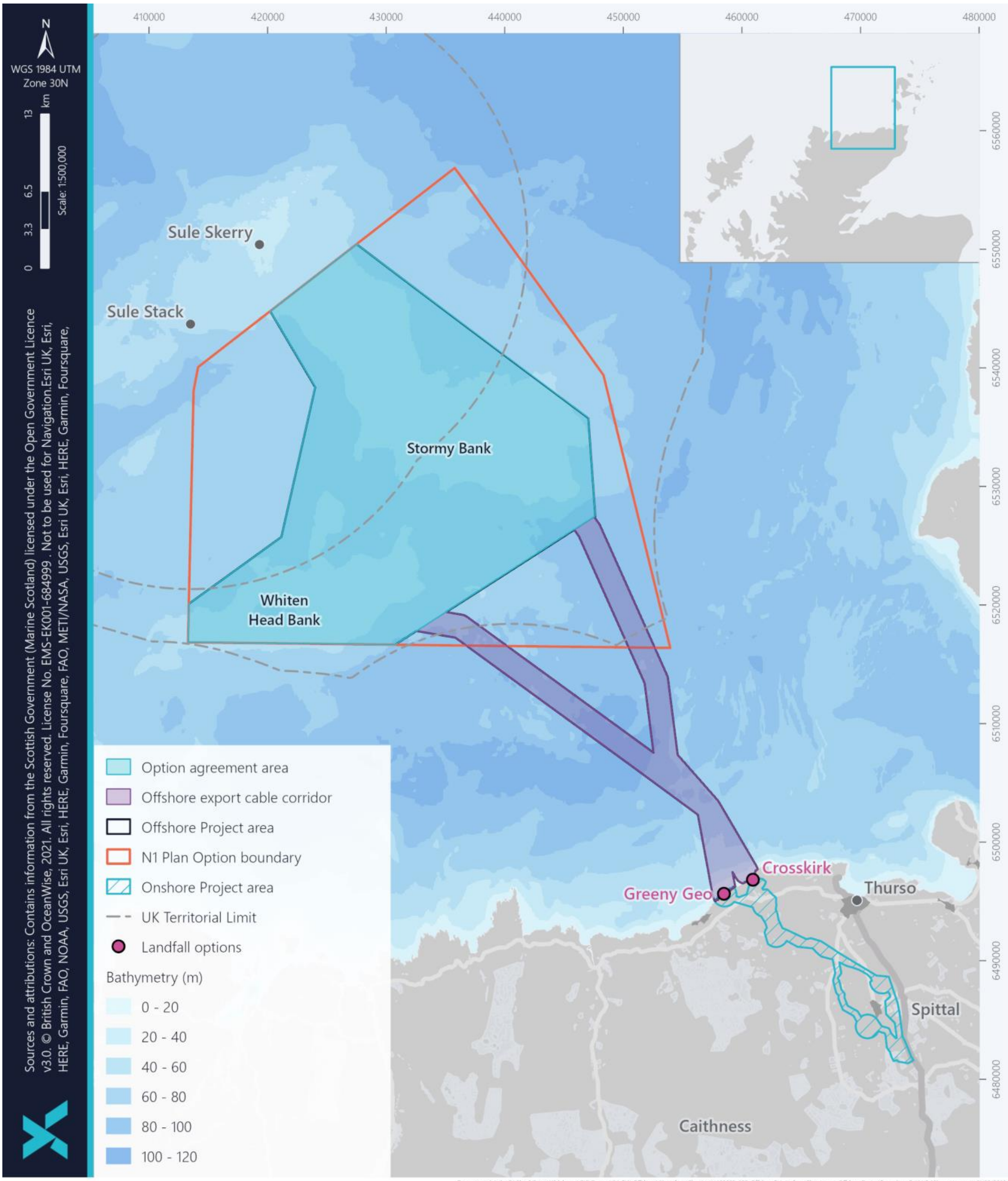

Figure 5-2 Offshore Project boundary

5.4 Pre-installation works

Several activities will be required ahead of construction, including Project-specific surveys, site investigations and site preparation.

5.4.1 Project-specific surveys and site investigation

Geophysical surveys and geotechnical surveys will be undertaken within the OAA and offshore ECC ahead of construction and will be used to inform detailed design and site preparation requirements. The site-specific survey equipment is yet to be confirmed as this would be determined by the survey contractor. However, the geophysical survey equipment will likely include Multi-Beam Echo Sounder (MBES), Side-Scan Sonar (SSS), and magnetometer. The SSS will be piggyback with the magnetometer and will be towed behind the survey vessel, potentially using Ultra Short Baseline (USBL) positioning equipment. Geotechnical surveys are anticipated to consist of cone penetration tests, vibrocorers and down hole sampling.

An UXO survey will also be conducted to survey the pre-determined targets and confirm the status of potential UXOs (pUXOs) as well as confirmed UXOs (cUXOs). These surveys will be used to inform UXO clearance activities (if required). See section 5.4.2.1.

5.4.2 Site preparation

The requirement for site preparatory works will be informed by the final design of the offshore Project and following Project-specific surveys. Site preparation activities may include:

- UXO clearance;
- Boulder clearance;
- Pre-lay grapnel runs;
- Bedform clearance; and
- Dredging.

5.4.2.1 UXO clearance

It is not possible to quantify the exact number of UXO that may require detonation for this Offshore EIA Report until further Project-specific surveys are undertaken. If UXO are identified during Project-specific surveys, these will be avoided wherever possible through micro-siting. However, if UXO clearance is required, this will be licensed separately through a Marine Licence and European Protected Species (EPS) licence.

To ensure that UXO clearance is still considered within the EIA, the number and charge of UXO requiring detonation have been estimated based on review of site specific geophysical survey data and a desktop study (OWPL, 2023). It is expected that approximately 222 pUXO could be present across the offshore Project area, with 3 – 10% of these are expected to be cUXO. Therefore, up to 22 UXO devices are anticipated to require clearance.

Several different methods of detonation are currently being considered including High Order (HO), Low Order (LO) and LO deflagration. LO techniques generally use a lower amount of high explosives to initiate the charge and will be the main methodology considered. HO methods are considered to be a last resort, however, they have been included within the Project Design Envelope to ensure the worst case is being considered if it is required. The success of LO methods depends on the type and state of the cUXO, and there is always the risk that a HO event will occur when employing a LO technique.

The UXO clearance procedure would be subject to an agreed method statement detailed within the Marine Licence application submitted post-consent. An EPS licence would also be sought. The Project Design Envelope is presented in Table 5-1.

Table 5-1 Design envelope for UXO clearance

DESIGN PARAMETER	DESIGN ENVELOPE
Maximum number of UXO requiring detonation	22
Maximum size of UXO (net explosive quantity) (kg)	247
Method of detonation	Several options for detonation are being considered including: • High order: bulk explosive disposal charge is deployed and placed on or in close proximity to the cUXO; • Low order deflagration: A malleable metal (typically but not exclusively, copper) shaped charge is emplaced in very close proximity to the cUXO, to deliberately deflagrate it; and • Low order: Using an explosively formed magnesium projectile or thermite pellet (or similar) to penetrate the UXO case and to concurrently burn-out its main charge.
Maximum number of UXO requiring detonation in 24 hour period	One, depending on the number of cUXO and method of detonation.
Maximum total duration of clearance	22 days, depending on the number of cUXO and method of detonation.

5.4.2.2 Seabed preparation

5.4.2.2.1 Boulder clearance

Project-specific surveys will be used to determine the boulder clearance requirements for the offshore Project along the full length of the inter-array cable, interconnector cable and offshore export cable routes, as well as the WTG and OSP foundation locations. The offshore Project area is characterised by extensive boulder fields. Boulders will be avoided wherever possible through micro-siting. However, this may not be feasible in areas where a large number of boulders are present. Where boulders need to be cleared, this will be achieved using a boulder plough or grab, and boulders will be moved to a suitable distance to enable a safe and efficient installation. If boulder clearance is required, this will be licensed separately through a Marine Licence.

The number of boulders to be cleared cannot be estimated until further Project-specific surveys are undertaken during the post-consent stage. However, it is assumed that a corridor of up to 30 m in width must be cleared along the full length of the inter-array cables, interconnector cables and offshore export cables, as well as areas for WTG and OSP foundations, totalling an area of 30,442,900 m^2. The clearance width for the cables has been estimated to ensure there is a sufficient width for micro-routing, navigational contingencies and for the operation of the cable burial tools.

5.4.2.2.2 Pre-lay grapnel run

Following the Project-specific surveys and boulder clearance works, a Pre-Lay Grapnel Run (PLGR) will be undertaken along the full length (with the exception of crossings) of the final inter-array, interconnector and offshore export cable routes within the OAA and the offshore ECC. If any debris items are encountered, these will be recovered by the vessel for disposal or recycling ashore.

Typical widths for different grapnel types and assemblies range from 0.8 to 1.5 m and do not exceed 2 m. Therefore, a corridor of up to 2 m has been assumed for the inter-array cables, interconnector cables and the offshore export cables.

In case of rocky areas along the route, pre-cutting operations might be needed prior to the cable laying. The burial technique will be decided post-consent, once detailed geophysical and geotechnical data and the selection of cable installation contractor and equipment are available, as described in sections 5.5.3.2, 5.6.2, and 5.6.3.

The Project Design Envelope for boulder clearance is provided in Table 5-2.

Table 5-2 Design envelope for pre-lay grapnel run

DESIGN PARAMETER	DESIGN ENVELOPE
Maximum width for pre-lay grapnel run per cable (m)	2
Maximum area for the pre-lay grapnel run for inter-array cables (m^2)	1,000,000
Maximum area for the pre-lay grapnel run for interconnector cables (m^2)	300,000
Maximum area for the pre-lay grapnel run for offshore export cables (m^2)	640,000

5.4.2.2.3 Bedform clearance

The Project-specific survey data will be used to determine the requirement for bedform clearance. Bedform clearance may be required as cable installation tools often require a flat seabed surface to operate, and a level surface is also required for the installation of WTG and OSP foundations and for the placement of scour protection around the foundation. Bedform clearance will also reduce the potential for cable exposure during the operation and maintenance stage.

Bedform clearance is typically achieved through dredging techniques (e.g. by Trailing Suction Hopper Dredge (TSHD) vessel), jetting tools and Controlled Flow Excavators (CFE). Any dredged material would be disposed of at a licenced disposal site, either offshore or onshore.

The Project Design Envelope for bedform clearance is provided in Table 5-3. The area requiring clearance has been estimated using existing geophysical data. 3% of the inter-array and interconnector cable corridors, and 20% of the offshore ECC, are assumed to require bedform clearance. A 10% contingency has been considered for the interconnector and offshore export cables, whereas a 50% contingency has been included for the inter-array cables, given the uncertainty in their final layout and the longer length of these cables. The width of the bedform clearance has been estimated based on the maximum seabed footprint of the tools used for the inter-array and interconnector cables (up to 150 m). However, it has been assumed that the full width of the offshore ECC may require bedform clearance (i.e. 1,000 m) in certain areas. The height of bedforms to be cleared has been used to determine volume of sediment to be removed, along with a 10% contingency.

Table 5-3 Design envelope for bedform clearance

DESIGN PARAMETER	DESIGN ENVELOPE
Maximum area for bedform clearance for WTGs and OSPs(m^2)	222,500
Maximum volume of sediment removed for WTGs and OSPs (m^3)	250,000
Maximum area for bedform clearance for inter-array cables (m^2)	3,375,000
Maximum volume of sediment removed for inter-array cables (m^3)	382,360
Maximum area for bedform clearance for interconnector cables (m^2)	2,925,000
Maximum volume of sediment removed for interconnector cables (m^3)	382,360
Maximum area for bedform clearance for offshore export cables (m^2)	19,200,000
Maximum volume of sediment removed for offshore export cables (m^3)	495,000

5.4.2.2.4 Dredging

Dredging may be required for bedform clearance (as described above in section 5.4.2.2.3), for cable installation (as described in sections 5.5.3.2, 5.6.2, and 5.6.3) and at the Horizontal Directional Drilling (HDD) exit pits. If dredging is required, this will be licensed separately through a Marine Licence.

For cable installation, the burial technique will be decided post-consent, once detailed geophysical and geotechnical data and the selection of cable installation contractor and equipment are available, as described in sections 5.5.3.2, 5.6.2, and 5.6.3. The area of disturbance during installation, associated with the installation tool footprint, is 50 m. Further details are provided in sections 5.5.3.2, 5.6.2, and 5.6.3.

Dredging may be required at the HDD exit pits below Lowest Astronomical Tide (LAT). These HDD exit pits, also known as receiver pits, are usually required (dependent on ground conditions) to ensure that the duct ends, and the subsea cables are installed securely buried below the seabed. A typical HDD exit pit will be 10 m wide, 30 m long, up to 5 m deep. The material removed during the HDD exit pit creation will either be disposed of or stored *in-situ* beside the HDD exit pits. On completion of the installation works, the pit will either be backfilled or left to backfill by natural processes. Excavation can be done for the above by backhoe dredgers or suction dredgers depending on ground type and water depths. Further details can be found in section 5.6.4 and Table 5-21.

5.5 Offshore wind farm infrastructure

5.5.1 Offshore WTGs

5.5.1.1 Design

The WTGs convert wind energy to electricity and consist of rotor blades, towers, gearboxes, transformers, power electronics and control equipment. WTG technology is constantly evolving so the final model of WTG will be selected post-consent. A range of WTG options and associated dimensions are being considered against which the environmental impacts of the offshore Project have been assessed.

Each WTG will consist of a tower supported by a foundation structure, a nacelle atop of the tower which contains the mechanical and electrical generating components, and three rotating blades. The WTGs will be horizontal axis WTGs. The typical design of a WTG is presented in Figure 5-3.

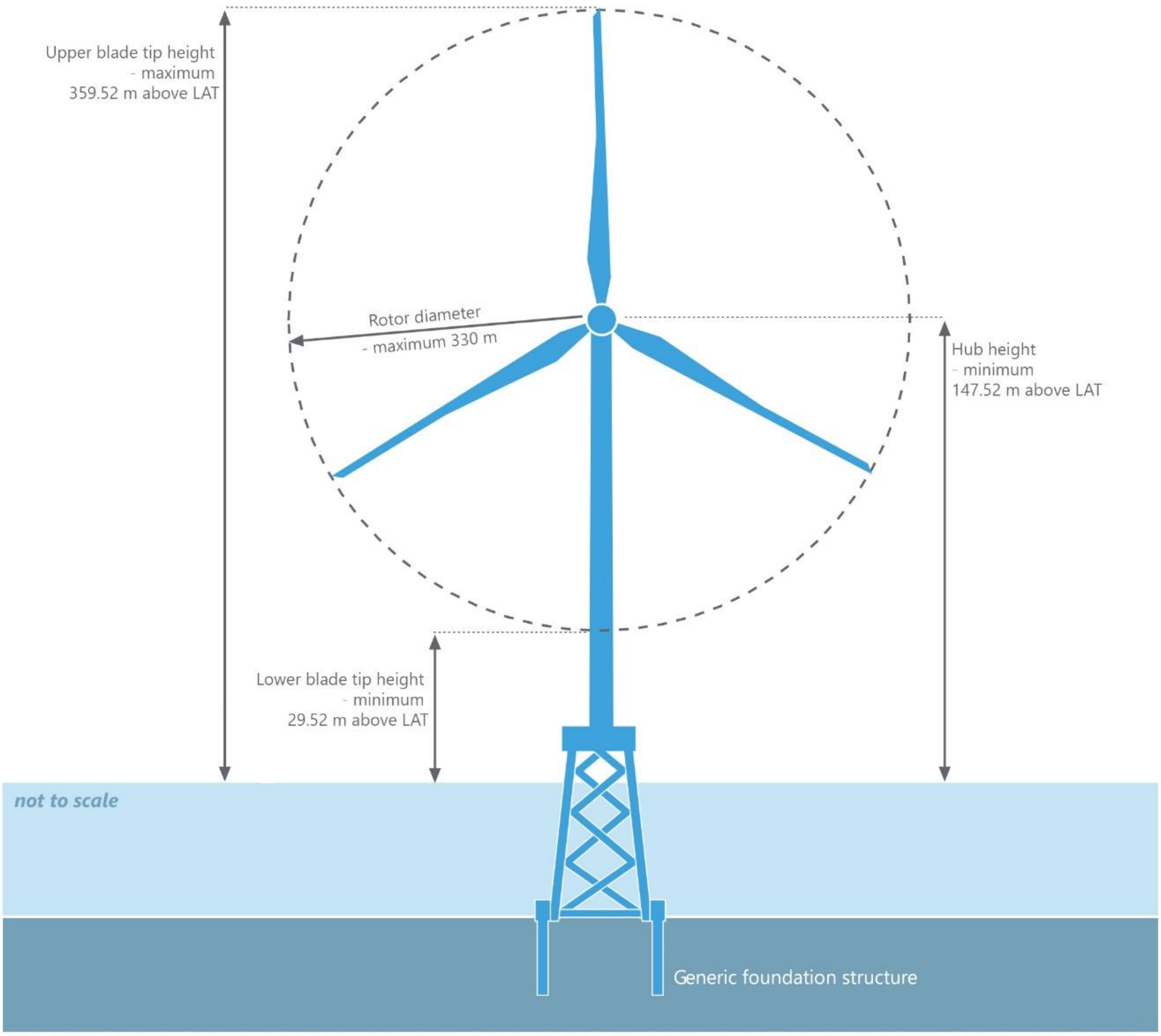

Figure 5-3 Typical design of a WTG

The anticipated Project Design Envelope for the WTGs is provided in Table 5-4. Multiple WTG design options are currently under consideration for the offshore Project. This flexibility is required to ensure the supply chain options at the point of construction can be met. The final WTG parameter values will remain within the Project Design Envelope provided in Table 5-4.

The minimum lower blade tip clearance will be at least 27.05 m above Mean Sea Level (MSL) in all tidal states. This clearance exceeds the navigational minimum of 22 m, as stipulated in Marine Guidance Note (MGN) 654. Ornithological collision risk modelling has been undertaken to inform this value in order to mitigate against potential adverse effects.

Table 5-4 WTG design envelope parameters

DESIGN PARAMETER	DESIGN ENVELOPE[1]
Anticipated operational life	30 years
Maximum number of WTGs	125
Minimum hub height above LAT (m)	147.52
Minimum lower blade tip height above LAT (m)	29.52
Maximum upper blade tip height above LAT (m)	359.52
Minimum rotor diameter (m)	236
Maximum rotor diameter (m)	330
Maximum swept area (m^2) (per turbine)	85,530
Minimum turbine spacing (m)	944

[1] Where relevant, the range of minimum or maximum values (depending on the design parameter) has been provided.

5.5.1.2 Layout

The WTG layout will be determined through the design optimisation process (post-consent). This process is iterative, balancing multiple key considerations including WTG model choice, WTG spacing arrangements, wind direction, geophysical characteristics, metocean conditions, foundation structure (and associated supporting structures) and navigational safety considerations, as well as environmental constraints such as key seabird populations, fisheries interests, sensitive seabed habitats, archaeological interests and seascape and landscape and visual issues. Within the OAA, each individual WTG will be micro-sited to consider positioning accuracy and any technical and environmental constraints at the time of installation.

The WTG layout where possible will follow specific design principles that have been developed throughout the EIA process in order to minimise environmental adverse effects:

- Minimum spacing of 944 - 1,320 m (depending on WTG model choice);
- Regular spacing between turbines and other structures preferred;
- Visually balanced layout;

- Avoidance of any outliers (WTGs or OSPs etc.);
- Off-set grid pattern preferred over a regular grid;
- Avoid splitting the array - one larger array preferred over two or more independently appearing developments; and
- Locate associated infrastructure and platforms within the overall array rather than on the outer edges.

An indicative layout is displayed in Figure 5-4. This is indicative only and the final layout will be based on further site investigation and detailed design studies conducted post-consent. Worst case scenario layouts have been developed for the relevant EIA topics and are presented in the topic-specific chapters.

5.5.1.3 Colour scheme, markings and lighting

The WTGs will be designed to satisfy the marking, lighting and fog-horn specifications of the Maritime and Coastguard Agency (MCA), Civil Aviation Authority (CAA) and the Northern Lighthouse Board (NLB).

As per industry best practice, the WTGs will be marked by lights that are visible from two nautical miles (nm) from all angles during construction. It is intended that the site will be marked as a buoyed construction area with the buoy locations agreed upon with NLB.

During operation, the WTG tower, nacelle and blades are likely to be Reichs-Ausschuss für Lieferbedingungen und Gütesicherung (RAL) 7035. Blades will be marked with red dots and 2% of the blade tip will also be marked red to assist with Search and Rescue (SAR) operations. The locations and characteristics of lighting, including on Significant Peripheral Structures (SPS)[5] and Intermediate Peripheral Structures (IPS)[6] will be dependent on the final WTG layout, which will be determined post-consent as described in section 5.5.1.2. However, marking and lighting will be in line with relevant regulations and guidance, including: aviation marking and lighting requirements, such as Article 223 of the Air Navigational Order 2016 (as amended), and maritime marking lighting requirements, such as International Association of Marine Aids to Navigation and Lighthouse Authorities (IALA) guideline G1162 and the MCA (2021) guidance on Offshore Renewable Energy Installations: Requirements, guidance and operational considerations for SAR and Emergency Response. Furthermore, marine navigational and aviation markings and lighting will be agreed with CAA, MCA and NLB post-consent.

The final position of all offshore structures will be communicated to the United Kingdom Hydrographic Office (UKHO) for incorporation into Admiralty Charts and notification procedures.

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[5] *SPS are corner structures or other significant points on the boundary of the OAA.*

[6] *IPS are on the boundary of the OAA between SPSA.*

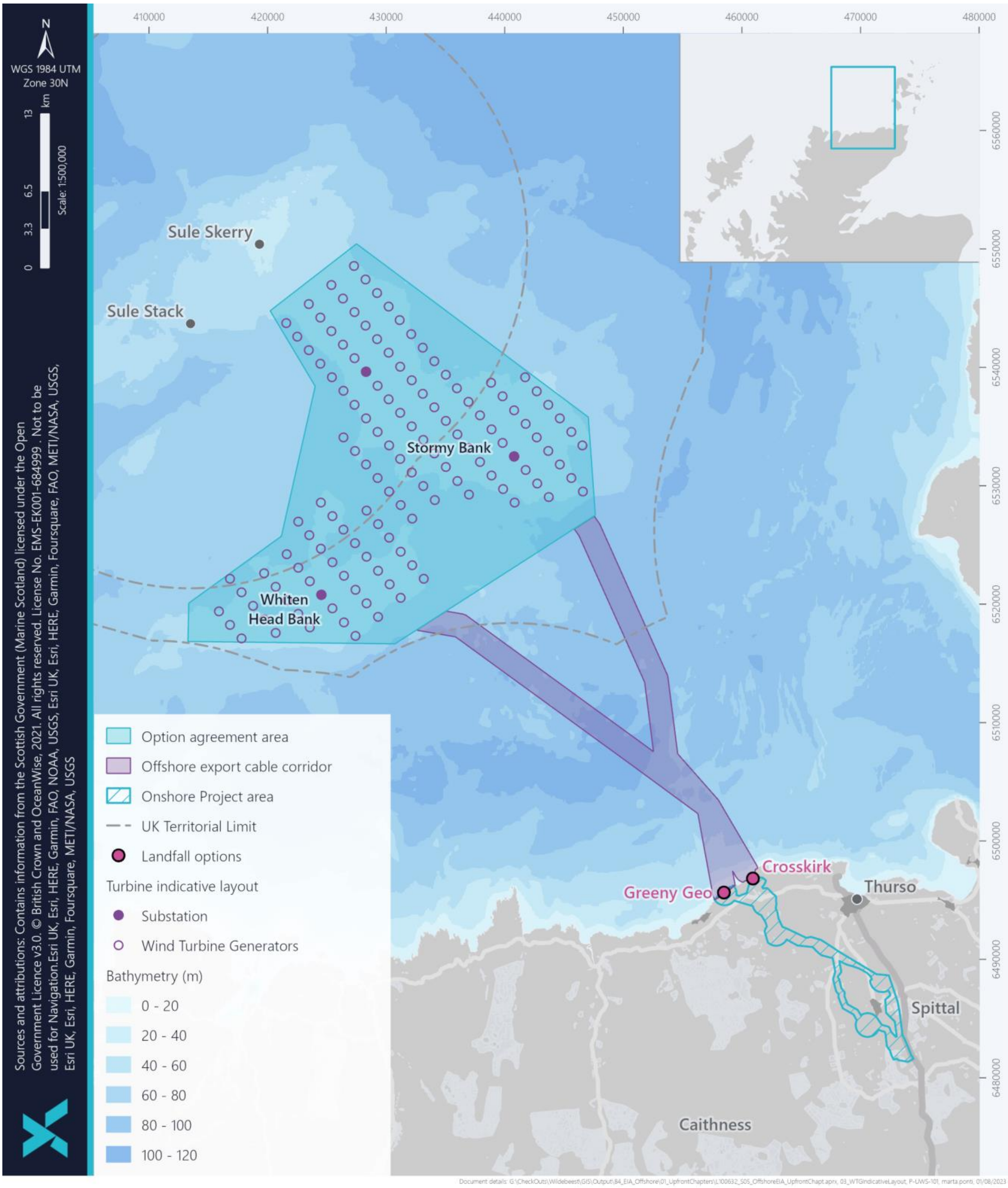

Figure 5-4 Indicative layout

5.5.1.4 Installation

The WTGs will be installed following the installation of the foundations (see section 5.9 for information on construction programme). The WTGs will be transported via a vessel from the construction base to the OAA for installation, either by a self-propelled installation vessel or transport barge. The construction base has not yet been identified, as this will depend on the Project-specific requirements based on the final design, the availability of ports at the time of construction and practical considerations, such as local facilities and ease of access. Therefore, the construction base will be determined nearer to the time of construction.

The installation vessels used will depend on the final WTG design option selected and availability of suitable vessels at the time of installation, however it is anticipated that the installation vessel will either be a Jack-Up Vessel (JUV) or a semi-submersible crane vessel. If installed by a JUV, the installation vessel will most likely erect the tower first at the installation location, lifting it onto the pre-installed foundation or transition piece, followed by the nacelle and rotor blades. If installed by a semi-submersible vessel, the WTG components may be loaded onto the vessel at a sheltered location or in port and the nacelle is installed onto a temporary tower on the deck of the vessel where the blades are pre-installed in advance of the tower being installed onto the transition piece or foundation. The nacelle and blade assembly is then installed onto the WTG tower.

The exact approach for the installation of the WTGs will depend on the final WTG design option and the installation contractor. This will be determined post-consent. Following installation of the WTG and connection to the inter-array cabling and wider infrastructure, a process of testing and commissioning will be undertaken.

5.5.2 WTG foundations

The WTGs will be supported by fixed-bottom foundations. The specific technology and makeup of the WTG foundations has not yet been selected, and the final technology selection will be driven by a series of environmental, technical and commercial variables, as technologies and methodologies continue to evolve. The following design options are being considered for the offshore Project:

- Monopiles; and
- Jacket foundations (piled or suction buckets).

Figure 5-5 presents schematics of the different foundation options. Additional foundation designs were considered through the design process and chapter 4: Site selection and alternatives provides reasoning for why they were discounted.

The foundations will be transported from the construction base to the OAA for installation via a self-propelled installation vessel or transport barge.

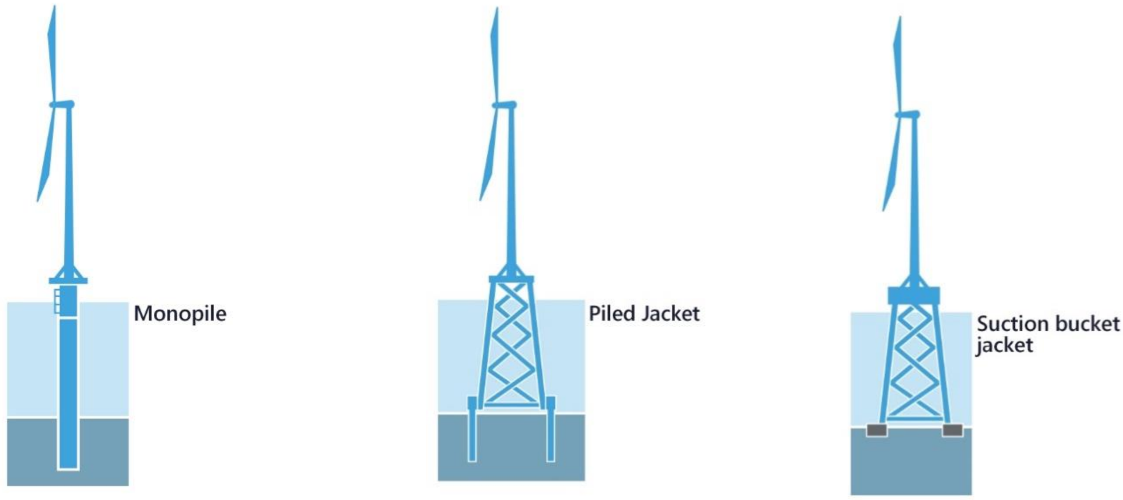

Figure 5-5 Foundation options

5.5.2.1 Monopile foundations

5.5.2.1.1 Design

Monopile structures consist of a single cylindrical column installed into the seabed. A transition piece may be fitted over the single column if required, either integral to the monopile itself or fitted once the monopile is installed. The transition piece may include ancillary components such as boat landing and working platforms, which allow for the WTG components to be installed and maintained. The transition piece is usually painted yellow (RAL 1023) and marked according to relevant regulatory guidance and may either be bolted or grouted. The Project Design Envelope for monopile foundations is provided in Table 5-5. Further details on the piling parameters used to inform the underwater noise modelling are provided in chapter 11: Fish and shellfish ecology and chapter 12: Marine mammals and megafauna.

Table 5-5 Design envelope for monopile foundations

DESIGN PARAMETER	DESIGN ENVELOPE
Maximum diameter (m)	14
Maximum height (m)	140
Maximum overall footprint (at surface) per WTG (m^2)	105

DESIGN PARAMETER	DESIGN ENVELOPE
Maximum proportion of depth above water (m, above LAT)	25
Maximum seabed footprint per WTG (m^2)	255
Maximum seabed footprint for Offshore Windfarm (OWF) (m^2)	31,875
Maximum seabed footprint for OWF with scour protection (m^2)	1,031,900
Piling characteristics	
Maximum number of piles per WTG	1
Maximum number of piles requiring piling across the OWF	125
Maximum diameter of pile (m)	14
Maximum hammer energy (kJ)	5,000
Maximum embedment depth (below seabed) (m)	50
Maximum duration (days) of piling operations	125 days across the construction period.
Drilling characteristics	
Maximum number of piles per WTG requiring drilling	1
Maximum drilling depth (below seabed) (m)	50
Maximum volume of drill arisings per pile (m^3)	11,000
Maximum volume of drill arising for OWF (m^3)	1,375,000

5.5.2.1.2 Installation

Project-specific surveys and site preparation works will be conducted ahead of installation, as described in section 5.4. Seabed preparations for WTG foundations are normally minimal but bedform clearance and boulder clearance may be required within the foundation footprints. Each monopile would then be installed in the following steps:

1. Upend monopile to a vertical position and lower to the seabed using craneage from installation vessel, which may be a heavy lift vessel, semi-submersible crane vessel or a JUV;
2. Deploy monopile piling template (if required) and drive monopile to required depth (in areas of poor ground conditions (e.g. hard substrata or rock) drilling may be required and is conducted ahead of the monopile being lifted into the drilled socket); and
3. Transition piece is lifted and secured onto the monopile, with grouting or bolting of connection as required.

It is anticipated that all piling operations will be initiated using a 20 minute 'soft start' procedure, where hammer energies are kept at 15% of the maximum, before gradually increasing to higher hammer energies (up to 5,000 kJ). The 'soft start' procedure is described further in section 5.8.2. Depending on the seabed conditions the maximum hammer energy would only occur at later stages of the piling operation, and at a few of the piling installation locations. Further assessments will be conducted post-consent, when the more detailed information on the ground conditions is available and the design has been finalised, in order to finalise the piling requirements.

In areas of poor ground conditions, driven only monopiles may not be feasible and drilling may be required. Drilling may be required for the full installation of the piles or it may be combined with piling in a 'drive, drill, drive' scenario. The drilling depth and the volume of drill arisings is provided in Table 5-5. If drilling is required, the spoil would be disposed of adjacent to the foundation location. No additional fluids are required for drilling only air and seawater.

Monopile installation may take up to 18 months in total, across up to three installation seasons (see section 5.9). The installation vessels used potentially include transport barges with associated tug vessels, semi-submersible crane vessels, JUVs and multi-purpose vessels.

5.5.2.2 Piled WTG jacket foundations

5.5.2.2.1 Design

Piled jackets are comprised of steel tubes that form a lattice rigid frame and will be three or four legged. The legs of the piled jackets are secured to the seabed by pin-piles attached to the jacket feet. The pin-piles for piled jackets have a smaller diameter than monopiles, but there will be up to four piles per WTG foundation (one per jacket leg).

The Project Design Envelope for piled foundations is presented in Table 5-6.

Table 5-6 Design envelope for piled WTG jacket foundations

DESIGN PARAMETER	DESIGN ENVELOPE
Maximum base length and width (m) (at surface)	20 x 20
Maximum height (m)	120
Maximum overall footprint (at surface) per WTG (m^2)	400

DESIGN PARAMETER	DESIGN ENVELOPE
Maximum proportion of depth above water (m)	40
Maximum number of legs per foundation	4
Maximum leg width (m)	3
Maximum jacket leg spacing (at seabed) (m)	41
Maximum jacket leg spacing (at surface) (m)	20
Maximum seabed footprint per WTG (m^2)	1,700
Maximum total seabed footprint for OWF (m^2)	213,000
Maximum seabed footprint for OWF including scour protection (m^2)	1,197,400
Piling characteristics	
Maximum number of piles per foundation	4
Maximum number of piles requiring piling across the OWF	500
Maximum diameter of pile (m)	3
Maximum embedment depth (below seabed) (m)	58
Maximum hammer energy (kJ)	3,000
Maximum duration (days) of piling operations	250 days across the construction period (two piles per day).
Drilling characteristics	
Maximum number of piles requiring drilling per WTG	4
Maximum drilling depth (m)	58
Maximum volume of drill arisings per pile (m^3)	665

DESIGN PARAMETER	DESIGN ENVELOPE
Maximum volume of drill arisings for OWF (m^3)	332,500

5.5.2.2.2 Installation

Project-specific surveys and site preparation works will be conducted at the site ahead of installation, as described in section 5.4. Seabed preparations for WTG foundations are normally minimal but bedform clearance and boulder clearance may be required within the foundation footprints. The piles and jacket structures will be transported to site, either by self-propelled vessels or transportation barges and associated tug vessels. Piles for piled jacket foundations will likely be pre-piled (i.e. piled in advance of the jacket structure being placed on the seabed), using a reusable seabed piling template. The seabed piling template would be lowered to the seabed and the piles would be installed through the seabed piling template. The jacket would then be secured to the piles after it has been lowered and grouted into position, potentially as part of a separate campaign (e.g. in the next construction year). Each jacket would be installed through the following steps:

1. Deploy piling template (if required) and drive each pile to the required depth (in areas of poor ground conditions (e.g. hard substrata or rock) drilling may be required and is likely to be conducted ahead of the pile being lifted into the drilled socket);
2. Cleaning of piles (if required);
3. Transportation of jacket to location and lift jacket onto existing piles; and
4. Grout jacket and install transition piece covers.

As described for monopiles, a soft start procedure would be implemented (described further in section 5.8.2) where hammer energies are kept at 15% of the maximum, before gradually increasing to higher hammer energies. However, as the piles are smaller than the monopiles, the maximum hammer energy required will be lower. Drilling may be required to supplement the pile driving to achieve the required seabed penetration, and it has been assumed, as a worst-case, that this will be required for all four piles per foundation. As for monopiles, drill arisings would be disposed of adjacent to the foundation structure.

Piled jacket installation may take up to 18 months in total, across up to three installation seasons. The installation vessels used potentially include transport barges with associated tug vessels, semi-submersible crane vessels, JUVs and multi-purpose vessels.

5.5.2.3 Suction bucket jacket foundation

5.5.2.3.1 Design

Similar to piled jacket foundations, a suction bucket jacket foundation also comprises a steel lattice frame, with up to three or four legs, but instead of being secured to the seabed via piles, it is secured to the seabed via suction buckets. Suction buckets are hollow cylindrical structures, sealed at the top and fitted underneath the legs of the jacket. The suction buckets penetrate the seabed through water pressure under the weight of the jacket.

The Project Design Envelope for suction bucket foundations is presented in Table 5-7.

Table 5-7 Design envelope for suction bucket jacket foundations

DESIGN PARAMETER	DESIGN ENVELOPE
Maximum base length and width (m) (at surface)	20 x 20
Maximum height (m)	120
Maximum overall footprint (at surface) per WTG (m^2)	400
Maximum proportion of depth above water (m)	40
Maximum number of legs per foundation	4
Maximum leg width (m)	3
Maximum jacket leg spacing (at seabed) (m)	41
Maximum jacket leg spacing (at surface) (m)	20
Maximum number of suction buckets per WTG	4
Maximum suction bucket diameter (m)	13
Maximum expected penetration depth (below seabed) (m)	30
Maximum seabed footprint per WTG (m^2)	2,100
Maximum seabed footprint for OWF (m^2)	263,000
Maximum seabed footprint for OWF including scour protection (m^2)	1,253,900

5.5.2.3.2 Installation

Project-specific surveys and site preparation works will be conducted at the site ahead of installation, as described in section 5.4. Seabed preparations for WTG foundations are normally minimal but bedform clearance and boulder clearance may be required within the foundation footprints The jacket structures, with suction buckets already attached, will be transported to the OAA, either by self-propelled vessels or transportation barges and associated tug vessels.

The suction bucket jacket foundations will be lowered to the seabed by the installation vessel and settled under the weight of the jacket structure initially. The water from the suction bucket is then pumped out to create a negative pressure within the suction bucket compared to the surround sea and secure the suction bucket to the seabed.

No pile driving or drilling is required for the suction bucket jacket foundation option. However, the use of suction buckets is dependent on the soil conditions. Suction bucket jacket installation may take up to 18 months in total, across up to three installation seasons. The installation vessels used potentially include transport barges with associated tug vessels, semi-submersible crane vessels, JUVs and multi-purpose vessels.

5.5.2.4 Scour protection for WTG foundations

Scour protection may be required to prevent structures being undermined by sediment processes and seabed erosion. The requirement for scour protection will be defined during the design process, as this will be dependent on the final offshore Project design.

Scour protection will likely consist of rock armour, consisting of graded stones placed on or around the structure that requires protection, with a thicker armour layer and a filter layer beneath it. Up to a maximum of 0.6 m median grain size rock may be used for the armour layer, and up to 0.1 m median grain size rock may be used for the filter layer.

Flexibility has been maintained in the type of scour protection, to account for new technologies that may be available at the time of construction, as these will be evaluated for the final design nearer to the time of construction. Other potential scour protection solutions currently under consideration include (amongst others):

- Concrete or rubber mattress protection – these are typically made up of concrete or rubber blocks linked together and are usually several metres wide and long;
- Rock, geotextile or filter bags – sand or rock filled fibre mesh bags; and
- Artificial fronds – made up of continuous lines of overlapping buoyant polypropylene fronds which prevent sediment being transported away. They are typically several metres wide and long and are secured to the seabed by a weighted perimeter.

The volume and likely locations of scour protection will depend on the final design of the substructures, and this will be determined post-consent following further Project-specific surveys, site investigations and detailed design studies. The Project Design Envelope for scour protection for the different foundation options is provided in Table 5-8.

Table 5-8 Design envelope for WTG substructure scour protection

DESIGN PARAMETER	DESIGN ENVELOPE
Monopile	
Scour protection material	• Rock placement; • Concrete or rubber mattress protection; • Rock, geotextile or filter bags; and • Artificial fronds.
Maximum extent of scour protection from edge of monopile (m)	41
Maximum area of scour protection per WTG (m^2)	8,000
Maximum volume of scour protection per WTG (m^3)	19,000
Maximum volume of scour protection for OWF (m^3)	2,380,000
Piled jacket foundations	
Scour protection material	• Rock placement; • Concrete or rubber mattress protection; • Rock, geotextile or filter bags; and • Artificial fronds.
Maximum extent of scour protection from each pile (m)	20
Maximum area of scour protection per WTG (m^2)	9,500
Maximum volume of scour protection per WTG (m^3)	23,500
Maximum volume of scour protection for OWF (m^3)	2,900,000

DESIGN PARAMETER	DESIGN ENVELOPE
Suction bucket foundations	
Scour protection material	• Rock placement; • Concrete or rubber mattress protection; • Rock, geotextile or filter bags; and • Artificial fronds.
Maximum extent of scour protection from each suction bucket (m)	20
Maximum area of scour protection per WTG (m^2)	9,500
Maximum volume of scour protection per WTG (m^3)	23,000
Maximum volume of scour protection for OWF (m^3)	2,860,000

5.5.3 Inter-array cables

The inter-array cables connect the WTGs together and to the OSPs. They transfer the generated electrical power from the WTGs. The cables branch out from the OSPs. The voltage of the inter-array cables will be up to 145 kV.

5.5.3.1 Design

The inter-array cables consist of three power cores and normally either one or two fibre optic communications cables. The power cores consist primarily of a metallic conductor enveloped with high integrity electrical insulation. The power cores and fibre optic are integrated into a complete cable package protected with steel wire armour.

Table 5-9 presents the Project Design Envelope for the inter-array cables. The layout of the inter-array cables will be optimised as part of the final design and determined post-consent. This will depend on the final WTG choice and the WTG layout.

Table 5-9 Design envelope for the inter-array cable design

DESIGN PARAMETER	DESIGN ENVELOPE
Maximum voltage (kV)	145
Cable specification	Three core power cable with integrated fibre optic communication cable(s).
Maximum external cable diameter (mm)	240
Maximum total length of inter-array cables (km)	500

5.5.3.2 Installation

Any seabed obstructions, including UXO, which cannot be avoided will be removed prior to cable installation where necessary, as described in section 5.4. The primary approach will be to microsite around any seabed obstructions or sensitive environmental receptors. A PLGR will be conducted to remove any surface debris.

The primary method of installation will be to bury the cable under the seabed to a target depth of 1 - 3 m, and this is also the primary approach to protecting the cable itself. The trench depth may increase down to 5 m depending on seabed conditions. A range of potential installation methods are currently being considered for the inter-array cables, with the potential for a combination of options to be used. This flexibility is required until the design of the offshore Project is finalised. The options being considered include cable plough, jet trenching, CFE, dredging, rock cutting, backfilling or other burial techniques, as outlined in Table 5-10. The seabed disturbance from the installation tool is based on the maximum width of an CFE tool (50 m), which will be required in discrete areas. The typical footprint for other installation tools is typically less than this, up to 15 m.

The inter-array cable installation can be approached using two methods:

- Post lay burial through separate cable lay and burial campaigns – the cable is first laid on the seabed or in a prepared trench then a second separate activity is undertaken to bury or cover the cable; or
- Simultaneous lay and burial through a single campaign.

Cables will be installed and/or laid by a cable installation vessel with cable burial potentially from a separate multi-purpose vessel.

The Project Design Envelope for the inter-array cable installation is presented in Table 5-11. Flexibility has been maintained in terms of the potential installation methods to be used. The installation method and target burial depth will be determined post-consent based on a Cable Burial Risk Assessment (CBRA), informed by Project-specific surveys and site investigations and secured within a Cable Plan (CaP).

Table 5-10 Cable installation tool options

CABLE INSTALLATION TOOL	DESCRIPTION
Cable plough	Cable ploughs use forward facing blade to cut and lift a wedge of seabed and create a slit trench into which the cable is then depressed. Cable ploughs are commonly used as part of a simultaneous lay and burial campaign, but also be used to post lay bury cables. The ploughs may be mounted on a self-propelled tracked vehicle or pulled directly from a surface vessel.
Jet trencher	Jet trenchers (either self-propelled or mounted as skids onto Remotely Operated Vehicles (ROVs)) inject water at high pressure into the sediment surrounding the cable. The seabed is temporarily fluidised and the cable is lowered to the required depth. Displaced material is suspended in the water and then resettles over the cable. Jetting may also be used for post-lay burial on a pre-laid cable.
Rock cutting	Cutting trenchers, which may be mounted as skids on ROVs or on tracked cable burial vehicles, are used in areas of harder substrate. Seabed is cut using chain, wheel or scoop type cutters to create a trench and the cable is subsequently laid within the trench. This can be used either as a pre-trench prior to cable laying or simultaneously with cable laying.
Controlled flow excavator	Controlled flow excavators inject a high volume of water at low pressure to displace seabed sediment. These can be used as a post-lay burial tool.
Dredger	TSHD operate by pumping water at a high pressure into the seabed and then suctioning it up into a hopper onboard the vessel. Backhoe dredgers are typically used in shallow or enclosed waters. They are a stationary vessel which mechanically excavates soil through a backward and upward movement.
Backfilling	The burial strategy may be to let the trench naturally backfill or mechanically backfill the trench.

Table 5-11 Design envelope for the inter-array cable installation

DESIGN PARAMETER	DESIGN ENVELOPE
Installation and burial methods	Trenching, dredging, jetting, ploughing, controlled flow excavation, rock cutting, backfilling or other burial technique. Either through separate cable lay and burial campaigns or a single simultaneous lay and burial campaign.
Maximum trench width (m)	5
Maximum width of seabed disturbance from installation tool (i.e. width of seabed footprint) (m)	50

DESIGN PARAMETER	DESIGN ENVELOPE
Maximum total area of seabed disturbance (m^2)	25,000,000
Target burial depth (m)	1 – 3

5.5.3.3 Crossings

No crossings between the inter-array cables and any third-party assets have been identified. However, up to 10 crossings between the inter-array cables and other inter-array cables, the offshore export cables and the interconnector cables have been allowed for. The number of crossings may be reduced once the WTG and OSP layout is finalised.

At the crossing points, the inter-array cables must be protected. This will likely occur using rock protection, concrete mattresses, grout / cement bags and Cable Protection Systems (CPS).

The Project Design Envelope for cable crossings is outlined within Table 5-12. The maximum footprint is associated with a trapezoidal berm profile with a 1:3 side slope.

Table 5-12 Design envelope for the inter-array cable crossings

DESIGN PARAMETER	DESIGN ENVELOPE
Anticipated number of crossings	5
Crossing material	Rock protection, concrete mattresses, grout / cement bags and CPS.
Maximum crossing height, length, width (m)	4 x 500 x 25
Maximum total area of crossings (m^2)	125,000
Maximum total volume of protection material across OWF (m^3)	260,000

5.5.3.4 Cable protection

The inter-array cables will be buried wherever possible as the primary means of protecting the cables. External protection (e.g. rock placement, concrete mattresses, grout bags, rock bags, cement bags, sandbags, articulated pipes, cast iron shells and/or bend restrictors) will only be used where adequate burial is not achievable or additional protection is required. Riser tubes may be required where inter-array cables transition from the seabed to the WTGs.

Table 5-13 summarises the Project Design Envelope parameters for inter-array cable protection. To inform this envelope, it has been assumed that areas with gravelly sand or sandy gravel could require external protection due to the difficulties in penetrating through these sediments. This results in an estimate of 20% of the total length of the inter-array cables requiring external protection. However, it is expected that the actual cable protection requirements will be less than this, as burial could be achieved in gravelly sand or sandy gravel sediment types, subject to certain conditions. The exact amount and location of cable protection required will depend on the mobility of the seabed around the cables and the depth of burial achieved. This will be determined post-consent, based on a CBRA, informed by Project-specific surveys and site investigations, and secured within a CaP. The cable protection will not exceed the maximum 5% reduction in the surrounding depths referenced to Chart Datum, as advised by the MCA to ensure safe navigation. If this is likely to occur in the nearshore areas, discussions will be held with Marine Directorate - Licensing Operations Team (MD-LOT) and relevant stakeholders such as MCA to agree reduction.

Table 5-13 Design envelope for inter-array cable protection

DESIGN PARAMETER	DESIGN ENVELOPE
Cable protection material	Concrete mattresses, rock placement, grout bags, rock bags, cement bags, sandbags, articulated pipes, cast iron shells, bend restrictors., filter units and gabion bags.
Maximum length of cables requiring cable protection (m)	100,000
Maximum protection height and width (m)	3 x 20
Maximum total inter-array cable protection footprint for offshore windfarm (OWF) (m^2)	2,000,000
Maximum total inter-array cable protection volume for OWF (m^3)	3,300,000

A description of the potential cable protection options is provided in Table 5-14.

Table 5-14 Cable protection options

CABLE PROTECTION OPTION	DESCRIPTION
Concrete mattresses	Concrete blocks linked together. This protection measure is frequently used to protect subsea cables and can also be used to construct crossings over existing subsea cables and pipelines. Typically, concrete mattresses are deployed using a crane and positioned using either divers or an ROV.

CABLE PROTECTION OPTION	DESCRIPTION
Rock placement	Made up of graded stones placed on or around the structure that requires protection to form trapezoid rock berms. The length of the berm depends on the length of cable requiring protection. Rock is typically deployed by a fall pipe vessel.
Grout bags, rock bags, cement bags and sand bags	Bags filled with grout, rock, cement or sand (which sets in water to the profiled shape) can also be used to provide very localised protection. They are typically deployed by a crane.
Tubular products (e.g. articulated pipe, cast iron shells and bend restrictors)	Cylindrical half shells that overlap to fix around a cable. These are generally only used over short sections of cable and can be installed around the cable on the vessel before the cable is deployed overboard, or retrospectively, potentially by divers. Bend restrictors may be used at the connection location to WTGs.

5.6 Offshore transmission infrastructure

5.6.1 Offshore substation platforms (OSPs)

A maximum of five OSPs will be required for the offshore Project. The OSPs will collect, transform and export the power generated by the WTGs. The OSPs contain electrical equipment and components required to transform the voltage of the electricity generated at the WTGs to a higher voltage suitable to export to the onshore grid network. The OSPs will be HVAC.

The OSPs will be located within the OAA, although the exact location for the OSPs has not yet been determined, and will be informed by further Project-specific surveys and site investigations, accounting for the WTG layout and offshore export cables. Indicative OSP locations have been identified for the WTG layout options, as described in section 5.5.1.2.

The typical design of an OSP is shown in Figure 5-6. The OSPs will consist of a 'topside' single or multi-level platform supported by pin-pile or suction bucket jacket foundations.

Figure 5-6 Typical OSP

5.6.1.1 Design of topsides

The topsides of the OSP will house the electrical equipment (e.g. switchgear) and ancillary components (e.g. helideck, service crane and met-mast antenna structure). The electrical equipment will be enclosed to protect from corrosion and prevent equipment damage. Table 5-15 presents the anticipated Project Design Envelope for the OSPs. The dimensions of the topsides will depend on the number and capacity of the platforms constructed.

Table 5-15 Design envelope for the offshore substation platform topsides

DESIGN PARAMETER	DESIGN ENVELOPE
Maximum number of OSPs	5
Maximum height of top of main structure (m, above LAT)	60.5
Maximum height of antenna structure (m, above LAT)	76.5
Maximum height of helideck (m, above LAT)	68.5
Maximum height of crane (m, above LAT)	72.5
Maximum length x width of each topside (m)	66 x 45
Maximum height of topside (m)	35

5.6.1.2 Design of the foundation

The OSP topsides will be supported by pin-piled jacket foundations or suction bucket jacket foundations. The jacket foundations will be similar to those described above for the WTGs. However, they will likely be larger in size due to the greater size of the topsides compared to the WTGs, with up to eight legs and 16 pin-piles per foundation. The Project Design Envelope for the OSP foundations is provided in section Table 5-16 and Table 5-17.

Table 5-16 Design envelope for the OSP piled jacket foundation

DESIGN PARAMETER	DESIGN ENVELOPE
Foundation design option	Piled jacket
Maximum number of legs per foundation	8

DESIGN PARAMETER	DESIGN ENVELOPE
Maximum leg width (m)	4
Maximum jacket leg spacing (at seabed) (m)	63
Maximum jacket leg spacing (at surface) (m)	45
Maximum seabed footprint per OSP (m^2)	3,700
Maximum seabed footprint per OSP with scour protection (m^2)	20,200
Maximum seabed footprint for all OSPs with scour protection (m^2)	101,000
Piling characteristics	
Maximum number of piles per OSP	16
Maximum diameter of pile (m)	3
Maximum embedment depth (below seabed) (m)	40
Maximum hammer energy (kJ)	3,000
Maximum duration (days) of piling	40 (two piles per day)
Drilling characteristics	
Maximum number of piles requiring drilling per OSP	16
Maximum drill depth (m)	40
Maximum volume of drill arisings per pile (m^3)	580
Scour protection	
Scour protection material	• Rock placement; • Concrete or rubber mattress protection; • Rock, geotextile or filter bags; and

DESIGN PARAMETER	DESIGN ENVELOPE
	• Artificial fronds.
Maximum area of scour protection per OSP (m^2)	16,500
Maximum volume of scour protection per OSP (m^3)	41,100
Maximum volume of scour protection for all OSPs (m^3)	205,500

Table 5-17 Design envelope for the OSP suction bucket jacket foundation

DESIGN PARAMETER	DESIGN ENVELOPE
Foundation design option	Suction bucket jacket
Maximum number of legs per foundation	8
Maximum leg width (m)	4
Maximum jacket leg spacing (at seabed) (m)	63
Maximum jacket leg spacing (at surface) (m)	45
Maximum suction bucket diameter (m)	8
Maximum expected penetration depth (below seabed) (m)	14
Maximum seabed footprint per OSP (m^2)	4,120
Maximum seabed footprint per OSP with scour protection (m^2)	21,420
Maximum seabed footprint for all OSPs with scour protection (m^2)	107,100
Scour protection	
Scour protection material	• Rock placement; • Concrete or rubber mattress protection; • Rock, geotextile or filter bags; and

DESIGN PARAMETER	DESIGN ENVELOPE
	• Artificial fronds.
Maximum area of scour protection per OSP (m^2)	17,300
Maximum volume of scour protection per OSP (m^3)	43,200
Maximum volume of scour protection for all OSPs (m^3)	216,000

5.6.1.3 Colour scheme, markings and lightings

As for the WTGs, the OSPs will be marked according to the most up to date regulatory requirements and guidance. This will be determined post-consent.

5.6.1.4 Oils, fluids and effluents

Each OSP will contain potential, fluids and effluents in order to operate. Typical substances include the following:

- Transformer oil;
- Batteries;
- Insulting gas;
- Engine oil;
- Diesel fuel;
- Sewage and grey water;
- Glycol;
- Corrosion protection coatings; and
- De-ionised water.

The OSPs will be designed in accordance with best practice to minimise the potential risk of release of hazardous substances. Furthermore, all chemicals will be certified to relevant environmental standards. All wastes (including oil waste, sewage waste and all other wastes), would be securely brought to shore and disposed of in accordance with industry best practice.

5.6.1.5 Scour protection for OSP foundations

Scour protection may also be required for the OSPs to mitigate against scour around the foundations. As described for the WTG foundations, it is likely that the scour protection will constitute rock placement. Other scour protection solutions include concrete or rubber mattresses, rock placement, rock, geotextile or filter bags and artificial fronds. The maximum area of scour protection (m^2) per OSP is provided in Table 5-16 and Table 5-17. The material, volume, area and locations of scour protection will depend on the final design of the OSP foundations, and this will be determined post-consent.

5.6.1.6 Installation

OSP foundations are pre-installed ahead of the topside structure. The installation of the pin-piled jacket foundation for the OSP will follow a similar process described for the piled jacket WTG foundation option described in section 5.5.2.2.

OSP foundations will either be pre-piled (i.e. piled in advance of the jacket structure being placed on the seabed) or post-piled. The pre-piled approach involves lowering a reusable seabed piling template onto the seabed and the piles installed through the seabed piling template. The jacket would then be secured to the piles after it has been lowered into position. Alternatively, the pin-piles may be post-piled, where piling occurs once the jacket is already in position. In this scenario, the piles are driven into the seabed through the legs of the jacket or through the jacket feet.

Drilling may be required in areas of difficult ground conditions (e.g. areas of rock or hard soils) and it has been assumed that drilling may be required for the full installation of the piles. The estimated volume of drill arisings per pile is provided in Table 5-16. If drilling is required, any spoil would be disposed of adjacent to the foundation location.

The topsides will be manufactured onshore and equipped with all electrical and mechanical equipment prior to being transported offshore to be installed atop of the OSP foundations. The topsides will be welded, grouted or bolted to the foundation. The OSP topsides will most likely be installed by a semi-submersible crane vessel.

The installation of up to 5 OSPs may take up to six months in duration spread over three installation seasons.

5.6.2 Interconnector cables

Interconnector cables will also be installed between the OSPs to improve transmission reliability. Table 5-18 presents the Project Design Envelope for the interconnector cables. The primary method of installation will be to bury the cables under the seabed, and this is also the primary approach to protecting the cable itself. External protection (e.g. rock placement, concrete mattresses and/or grout bags) will only be used where adequate burial is not achievable or additional protection is required.

A range of potential installation methods are currently being considered for the interconnector cables, with the potential for a combination of options to be used. The interconnector cables will be installed using the methods described for inter-array cables (section 5.5.3.2). The options being considered include cable plough, jet trencher, cutting trencher, CFE, dredging, rock cutting and backfilling, or other burial techniques. As described for inter-array cables, the seabed disturbance from the installation tool is based on the maximum width of an CFE tool (50 m).

As for the inter-array cables, the interconnector cables will be protected where they cross any other infrastructure. This will likely occur using rock protection, concrete mattresses, grout / cement bags and CPS. No crossings with third-party assets have been identified. However, up to 10 crossings have been allowed for across the entire offshore Project (as specified in section 5.5.3) between the interconnectors and other interconnectors, the offshore export cables and the inter-array cables. The number of crossings may be reduced once the WTG and OSP layout is finalised.

In addition to the cable protection methods listed for the inter-array cables, vortex-induced suppression strakes may also be used to protect the interconnector cables. This protection method wraps around the cable in a helical fashion and acts to supress vortex-induced vibrations whilst also providing impact and abrasion protection. Approximately 70% of the interconnector cables are estimated to require protection. This is a conservative estimated based on the anticipated ground conditions and the capabilities of the burial tools.

The final design, installation method and target burial depth will be determined post-consent based on a CBRA, informed by Project-specific surveys and site investigations, and secured within a CaP. The final design will sit within the Project Design Envelope presented in Table 5-18.

Table 5-18 Design envelope for interconnector cables

DESIGN PARAMETER	DESIGN ENVELOPE
Design	
Maximum voltage (kV)	420
Cable specification	Three core armoured power cables with up to two integrated communications cables.
Maximum cable diameter (mm)	330
Maximum number of cables	6
Maximum total length of cabling (km)	150
Installation	
Installation and protection methods	Trenching, dredging, jetting, ploughing, controlled flow excavation, rock cutting, backfilling or other burial technique. Either through separate cable lay and burial campaigns or a single simultaneous lay and burial campaign.
Maximum trench width (m)	5
Maximum width of seabed disturbance from installation tool (i.e. width of seabed footprint) (m)	50
Maximum total area of seabed disturbance (m^2)	7,500,000
Target burial depth (m)	1 – 3

DESIGN PARAMETER	DESIGN ENVELOPE
Crossings	
Details provided in section 5.5.3.	
Cable protection	
Cable protection material	Concrete mattresses, rock placement, grout, rock bags, bags, cement bags, sandbags, articulated pipes, cast iron shells, bend restrictors, vortex-induced vibrations suppression strakes.
Maximum length of cables requiring cable protection (m)	99,000
Maximum protection height and width (m)	3 x 20
Maximum total interconnector cable protection footprint for OWF (m^2)	1,980,000
Maximum total interconnector cable protection volume for OWF (m^3)	3,267,000

5.6.3 Offshore export cables

The offshore export cables, each correspond to an HVAC submarine power cable system consisting of a three-core armoured submarine power cable with one (or more) fibre optic cables embedded in the main submarine cable. The offshore export cables will export energy from the OSPs to the onshore export cables via the offshore / onshore interface at the landfalls. Up to five offshore export cables will be required across the offshore Project to the two landfalls at Caithness. The offshore export cables will be located in separate trenches within the offshore ECC, as displayed in Figure 5-2. At approximately 13 km from the landfalls at Caithness, the offshore ECC diverges into two cable route options, to the east and west of the OAA. The offshore export cables will either be split across these two cable route options or located within one of the two cable route options, and this will be determined post-consent. The offshore ECC is 1,000 m in width at its widest point and the anticipated spacing between the offshore export cables is 170 m within this area. The minimum spacing between the offshore export cables is determined to reduce risk of damage during installation and repair operations and maintain access to adjacent cables once a repair has been completed.

The primary method of installation will be to bury the cable under the seabed, and this is also the primary approach to protecting the cable itself. As for the interconnector cables, the options for external protection include concrete mattresses, rock placement, rock bags, grout bags, cement bags, sandbags, articulated pipes, cast iron shells, bend restrictors and vortex-induced suppression strakes, and this will only be used where adequate burial is not achievable or additional protection is required.

The offshore export cables will be installed using the methods described for the inter-array and interconnector cables (section 5.5.3.2). The options being considered include trenching, dredging, jetting, ploughing, controlled flow excavation, rock cutting, backfilling or other burial technique. The seabed disturbance from the installation tool is based on the maximum width of an CFE tool (50 m), which will be required in discrete areas, including at the transition length between the HDD exit point and burial areas. The footprint for other installation tools is generally less than this, typically up to 15 m.

No crossings with existing third-party infrastructure have been identified. However, a crossing with the proposed Scottish Hydro Electric Transmission Limited (SHET-L) Caithness to Orkney HVAC Link may occur if this development is brought forward. The likely crossing material includes concrete mattresses, rock placement, grout / cement bags, articulated pipes, filter units, rock bags, cast iron shells, bend restrictors and other cable protection systems. The detailed design of the crossing will be developed in conjunction with SHET-L and OWPL will seek to enter into a crossing agreement. It is anticipated that 5 crossings will be required in relation to the export cables.

Up to 29% of the offshore export cable routes may potentially require external protection, based on the anticipated ground conditions and the capabilities of the burial tools.

The Project Design Envelope parameters for the offshore export cables are provided in Table 5-19. The design, installation method and target burial depth will be determined post-consent based on a CBRA, informed by Project-specific surveys and site investigations and secured within a CaP.

Table 5-19 Design envelope for the offshore export cables

DESIGN PARAMETER	DESIGN ENVELOPE
Design	
Maximum voltage (kV)	420
Maximum external cable diameter (mm)	330
Maximum number of cables	5
Total maximum cable length (km)	320
Anticipated spacing between cables (m)	170
Installation	
Installation and protection method	Trenching, dredging, jetting, ploughing, controlled flow excavation, rock cutting, backfilling or other burial technique.

DESIGN PARAMETER	DESIGN ENVELOPE
Maximum width of seabed disturbance from installation tool (i.e. width of seabed footprint) (m)	50
Maximum total area of seabed disturbance from installation tool (m^2)	16,000,000
Maximum trench width (m)	5 m
Target burial depth (m)	1 - 3
Cable crossings	
Crossing material	Concrete mattresses, rock placement, grout/cement bags, CPS
Anticipated number of crossings	Up to 5
Maximum crossing height, length, width (m)	4 x 500 x 25
Maximum total area of crossings (m^2)	62,500
Cable protection	
Cable protection material	Concrete mattresses, rock placement, rock bags, grout bags, cement bags, sandbags, articulated pipes, cast iron shells, bend restrictors, and vortex-induced vibrations suppression strakes.
Maximum length of cables requiring cable protection (m)	93,500
Maximum cable protection width (m)	20
Maximum cable protection height (m)	3
Maximum total cable protection footprint for the offshore export cables (m^2)	1,870,000
Maximum total offshore export cable protection volume for OWF (m^3)	3,085,500

5.6.4 Landfall

The landfall locations under consideration are at Greeny Geo and Crosskirk, as outlined within section 5.3. The landfall is an interface between the offshore and onshore aspects of the Project. As such the construction work will typically involve both offshore and onshore elements.

It is currently anticipated that the five offshore export cables may landfall into a single location at either Crosskirk or Greeny Geo. However, if constrained, the offshore export cables will be split across these two landfall options. HDD is the only technique being considered for the installation of the offshore export cables at the landfalls, and a description of this technique provided in Table 5-20. Due to the cliff features at both the Crosskirk and Greeny Geo, Open Cut Trenching (OCT) was not deemed feasible, and rock-pinning was also assessed as unsuitable due to the significant cable sizes and the requirement for diver operations in dangerous cliff areas.

At the landfalls, one concrete Transition Joint Bay (TJB) may be required per offshore export cables to house the interface joint between the offshore export cables and onshore export cables. The TJBs may also be split across the two landfall options. However, this would be located above MHWS, and therefore, forms part of the onshore Project, and is not considered in this Offshore EIA Report.

Table 5-20 Description of HDD landfall installation technique

DESCRIPTION
Horizontal Directional Drilling (HDD)
HDD is a trenchless landfall installation technique, which involves drilling through the ground from an onshore HDD site compound to a point offshore beyond the intertidal zone and ideally with sufficient water depth for the cable lay vessel to access. The hole may be drilled in a number of passes to enlarge the drill sufficiently to eventually pass the product pipe through. The HDD exit points are expected to be located between 10 m and 40 m water depths. The following general HDD procedure will be followed: 1. Mobilise onshore equipment for the HDD works and construction of the onshore HDD compound; 2. Excavation of material at the HDD exit points to create an HDD exit pit, as required; 3. Drilling of pilot holes from the onshore HDD entry point, beneath the intertidal area to the HDD exit point using a drill bit and drill head. Inert drilling fluids are injected into the pilot holes behind the drill head, and a small quantity may be discharged into the marine environment; 4. Once the drill bit exits the HDD exit pit, the drill head is removed and the pilot holes are enlarged to the required diameter by reamers attached to the drill string, potentially across several passes to reach the necessary size for the cable ducts; 5. The cable ducts are installed from the HDD entry point; 6. Prior to the offshore export cable installation activities, the cable pull-in operation will commence where the offshore export cable are pulled ashore through the ducts from an installation vessel; and 7. The remaining section of the offshore export cables are installed, and the onshore HDD equipment is removed.

The drilling fluids will be formulated from bentonite powder, a non-toxic and inert natural clay mineral. Approximately 40 kg of bentonite powder is added per 1,000 Litres of water to make up the drilling fluids, and soda ash is typically added during the mixing process to condition the water to the correct pH. If drill fluid losses occur, Lost Circulation Material (LCM) may be added to the drilling fluid to seal permeable areas (e.g. sugar or cellulose starch-based product). Alternative polymer drilling fluids, such as Pure-Bore may also be used for at the HDD exit point and during the pull reaming when the fluid is lost at sea. Grout would only be expected to be required to seal any fractures in the rock if multiple efforts with LCMs were unsuccessful. All drilling fluids are biodegradable and would be certified to relevant environmental standards (e.g. Centre for Environment, Fisheries and Aquaculture Science (Cefas) registered).

Excavation at the HDD exit pits may be required to ensure the duct ends and subsea cables are sufficiently buried below the seabed, as described in section 5.4.2. The material would be disposed of or stored beside the HDD exit pits and may be used to infill the HDD exit pit after the operation.

Cable protection may also be required for any exposed sections of offshore export cable in this area, including by concrete mattresses, rock placement, grout bags, rock bags, cement bags, sandbags, filter units, articulated pipes, cast iron shells, bend restrictors, and vortex-induced vibrations suppression strakes. The Project Design Envelope for this external protection is included within the parameters described in section 5.6.3.

The anticipated Project Design Envelope for the landfall infrastructure is provided in Table 5-21.

Table 5-21 Design envelope for landfall infrastructure

DESIGN PARAMETER	DESIGN ENVELOPE
Installation method	HDD
Maximum number of ducts installed	6
Maximum HDD duct length (m per duct)	Up to 1,200
Anticipated Location of HDD exit point (m, below LAT)	Between water depth of 10 m – 40 m below LAT, within the offshore ECC.
Maximum dimensions of HDD exit pits (length m x width m x depth m)	30 x 10 x 5
Maximum volume of material excavated from all exit pits (m^3)	9,000

5.7 Other offshore infrastructure and ancillary equipment

A metocean survey has been ongoing within the OAA since October 2022 and is anticipated to continue for at least 12 months. As part of this survey there are four items of equipment deployed including two floating light detection and ranging systems, one seabed mounted acoustic doppler current profiler and one wave buoy. All of the deployments are exempt under the Marine Licensing (Exempted Activities) (Scottish Inshore Region) Order 2011, the Marine Licensing (Exempted Activities) (Scottish Offshore Region) Order 2011 and the Marine Licensing (Exempted Activities) (Scottish Inshore and Offshore Regions) Amendment Order 2012.

Additional ancillary equipment may be required as part of the construction process may be required including:

- Mooring systems,
- Charging systems and batteries; and
- Further in-field measuring and monitoring systems (e.g. floating LiDAR, wave buoys).

5.8 Residues, emissions and waste

The expected residues, emissions and waste associated with the offshore Project are detailed below. Residues, emissions and waste will be controlled and mitigated, as required, to minimise any potential adverse effects on the surrounding environment.

5.8.1 Hazardous substances

The key potential sources of hazard substances associated with the offshore Project include:

- Oils, fuels and effluence necessary for the operation of the WTGs and OSPs;
- Anti-corrosion coatings above – 4.05 m LAT up to connecting flange level, with external cleaning every two years;
- OSP discharges; and
- Accidental releases of hazardous substances from vessels associated with the offshore Project.

Measures will be adopted to reduce any potential discharge of hazardous substances associated with the offshore Project. As described in section 5.5.1.4 and 5.6.1.4, oils, fuels and effluents will be necessary for the operation of the WTGs and OSPs. These will be stored and managed in line with best practice (e.g. bunded storage tanks) to reduce any potential spillage into the marine environment. Anti-corrosion paints on steelwork vulnerable to corrosion will follow relevant best practice measures and regulations (e.g. ISO 12944 and ISO 8501-3). Any OSP discharges (e.g. oil waste) will be securely brought back to shore and disposed of in line with best practice.

Vessels associated with the construction, operation and maintenance and decommissioning of the offshore Project will also contain hazardous materials. However, the risk and impact of accidental releases of hazardous substances will be reduced through the implementation of the construction and operational Environmental Management Plan including measures for compliance with international requirements of the MARPOL convention, as well as best practice for works in the marine environment (e.g. preparation of Shipboard Oil Pollution Emergency Plans (SOPEP)) (Offshore EIA Report, Outline Plan (OP) 1: Outline Environmental Management Plan).

5.8.2 Underwater noise

The main sources of underwater noise from the offshore Project are impact piling of substructures, as these activities can generate high underwater noise levels. A range of factors will influence the underwater noise levels associated with piling, including but not limited to the duration of activities and the diameter and length of the piles. Information on the Project Design Envelope for WTG substructures is provided in section 5.5.2 and for OSP substructures in section 5.6.1.

UXO clearance is also a key underwater noise source from the offshore Project. The underwater noise emitted will depend on the final number, size and clearance approach taken. The Project Design Envelope is provided in section 5.4.2.1. Other noise sources will also be associated with the pre-construction, construction, operation and maintenance and decommissioning of the offshore Project. These sources are likely to include cable laying, dredging, drilling, rock placement for seabed preparation, vessel movements (including acoustic positioning systems) and operational WTG noise.

Further details on the underwater noise associated with the offshore Project is provided in the Offshore EIA Report, Supporting Study (SS) 10: Underwater noise modelling report, chapter 11: Fish and shellfish ecology and chapter 12: Marine mammals and megafauna.

5.8.3 Light

Artificial lighting on WTGs and OSPs will be installed in line with aviation and maritime lighting requirements, as discussed in sections 5.5.1.3 and 5.8.3. The vessels will also be associated with artificial light, although this will be kept to a minimum whilst still allowing for safe operations.

5.8.4 Electromagnetic fields (EMF)

The transmission of electricity through subsea cables generates Electromagnetic Fields (EMFs). EMF generated by offshore cables are considered as additional sources of EMF as the earth itself has its own geomagnetic field and hence EMFs are always present. The inter-array, interconnector and offshore export cables produce EMFs, which have both Electric (E) components, measured in Volts per metre ($V\ m^{-1}$), and magnetic components (B), measured in micro Tesla (μT). While the direct electric field is encapsulated within the cable structure through electrical insulation and a metallic screen, the B-field is virtually impossible to contain and penetrates most materials. Therefore, B-fields are emitted into the marine environment, with the resultant induced Electric (iE) field, causing a highly localised change in EMFs.

HVAC cables result in a dynamic, low-frequency sinusoidal B-field (Gill and Desender, 2020). The dynamic alternating B-field causes relative motion between the cable's B-field and the surrounding water, which therefore generates a weak iE-field in close proximity to the cable (Taormina *et al.*, 2018). Natural iE-fields also result from sea water interacting with the geomagnetic field, due to relative motion caused by the Earth's rotation, and tidal currents (Gill and Desender, 2020). The strength of iE-fields increases with current flow and both B and iE field strengths decrease with distance from the cable (Taormina *et al.*, 2018).

Commonly cable burial is used to increase the distance between the cable and the electro-sensitive species (Taormina *et al.*, 2018; Gill and Desender, 2020). However, where burial is not possible; cable protection, rock placement or other similar established techniques, increases the distance between marine species sensitive to EMF and the EMF source.

A Project specific modelling study by was undertaken by a cable manufacturing company (currently confidential) to model the predicted changes in EMF, focussing on B-fields from the inter-array cables and offshore export cables. 66 kV inter-array cables at 691 A and 275 kV offshore export cables at 972 A were modelled. It is acknowledged that these voltages are less than those being proposed for the offshore Project. However, it is important to note that potential B-fields are proportional to cable current, and a higher voltage results in a smaller current. Therefore, modelling B-fields for these lower currents represents the worst case.

Table 5-22 presents the results of the Project specific modelling study, representing the B-fields at the seabed surface at 0, 1, 2 and 3 m burial depths (where cable protection of up to 3 m can be treated the same as burial depth). The B-fields rapidly dissipate when assuming 1 -3 m burial or cable protection. Furthermore, the approximate natural geomagnetic field at the offshore Project area is 50 μT, and in all cases, the B-fields are less than this at 1 m burial or protection depth.

Table 5-22 Magnetic (B) fields at the seabed surface at various burial depths for the inter-array and offshore export cables

COMPONENT	BURIAL DEPTH (M)			
	0	1	2	3
Inter-array cable B-fields	348 μT	9.3 μT	2.8 μT	1.3 μT
Offshore export cables B-fields	507 μT	18 μT	5.7 μT	2.7 μT

5.8.5 Heat

For any buried portions of cable, warming of the surrounding sediment may occur, which can negatively impact demersal marine fauna (Taormina *et al.*, 2018). There is uncertainty in the magnitude of this impact as heating effects from subsea cables are not well researched. The one field study carried out so far, at the Nysted wind farm on a 166 MW cable, found that the rise in temperature did not exceed 1.4°C in 20 cm depth above the cable and no relationship was established between power transmission and temperature increase (Meißner *et al.*, 2006).

5.8.6 Spoil disposal

Site preparation and drilling during the construction period, associated with the installation of the WTG and OSP substructures and the excavation works associated with the HDD exit pits, may generate spoil material, as described in sections 5.4.2.2.3, 5.5.2 and 5.6.4. The spoil will be disposed of, either adjacent to the dredged or drilled area or in a licenced disposal site (either offshore or onshore).

5.8.7 Waste

All wastes (e.g. oil wastes and wastewater) will be contained and recovered for disposal onshore by an approved waste management company. Waste management procedures will also be developed for contractors and personnel working at the offshore Project.

All vessels will be equipped with waste disposal facilities (sewage treatment or waste storage) to IMO MARPOL Annex IV Prevention of Pollution from Ships standards. Ballast water discharges from vessels will be managed under International Convention for the Control and Management of Ships' Ballast Water and Sediments, 2004 (Ballast Water Management (BWM) Convention).

5.9 Construction programme and sequencing

It is anticipated that the construction of the offshore Project will take up to four years (subject to change), with an additional one year of pre-construction/site preparation works.

The timing of the construction programme is indicative and will depend on a number of factors, including but not limited to:

- Timing of Transmission Entry Capacity;
- The date that a CfD is awarded (dependent on the Project gaining necessary consents);
- Contractor and vessel selection and/or availability;
- Ground conditions;
- Weather conditions; and
- Other supply chain or logistical issues.

The general series of activities is as follows:

1. Project-specific surveys and site-investigations (section 5.4.1);
2. Site and seabed preparation (section 5.4.2);
3. WTG foundation installation (section 5.5.2);
4. OSP installation (section 5.6.1);
5. Offshore export landfall and offshore installation (section 5.6.3 and 5.6.4); Inter-array and interconnector cable installation (section 5.5.3 and 5.6.2); and
6. WTG installation / commissioning (section 5.5.1).

The indicative construction programme is presented in Figure 5-7. Offshore construction may last up to four years, under the assumption that construction activities occur within distinct construction seasons with delays between each season (i.e. construction is not continuous throughout this period). It may be possible for construction activities to be continuous through the construction stage to reduce the overall construction duration. Construction works would typically be undertaken 24 hours a day, seven days a week offshore, dependent upon weather conditions. It is anticipated that construction will only occur up to nine months a year. Weather conditions during the winter months, particularly November to January, are unlikely to be suitable for offshore construction. Therefore, construction will occur over multiple seasons across the four years to avoid adverse weather conditions, and first power may occur ahead of the construction stage being complete.

Durations for major works are subject to change, which may arise, for example, from weather or site conditions. Furthermore, specific details on installation will vary depending on the technologies adopted and may change due to improvements in both the technology and supply chain.

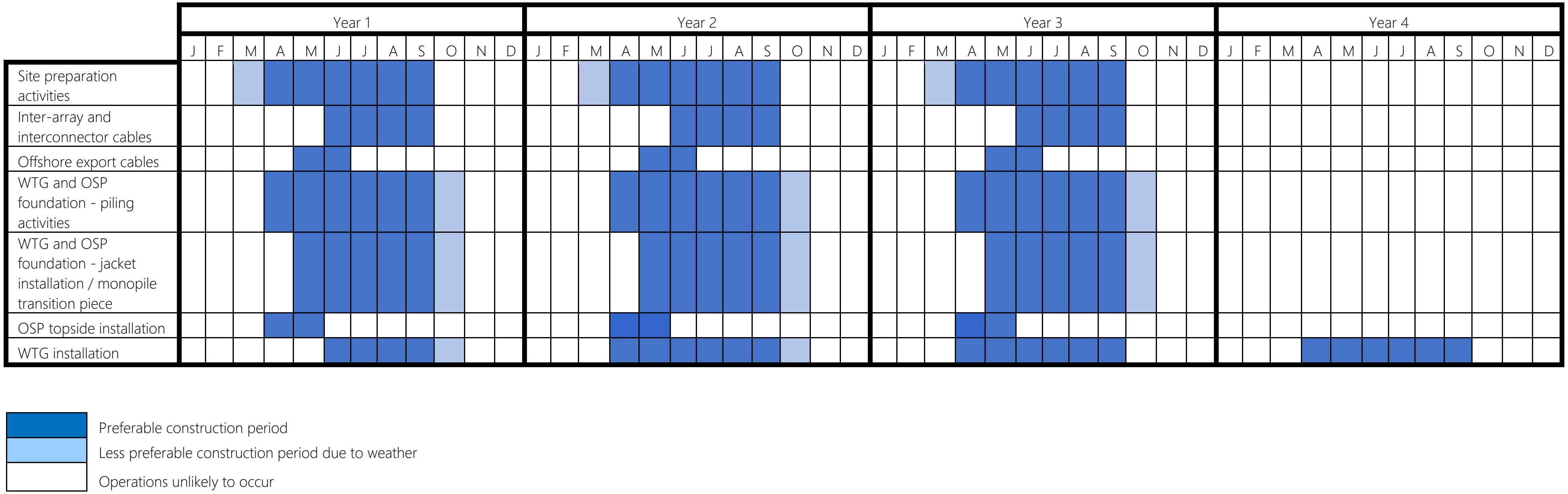

Figure 5-7 Indicative construction programme

5.9.1 Construction vessel requirements

The vessel requirements will be determined by the installation contractor post-consent, and this will depend on vessel availability. However, it is anticipated that a range of vessels will be used in the construction stage, including:

- JUVs;
- Semi-submersible crane vessels;
- Transportation barges and tugs;
- Cable laying vessels;
- Service Operation Vessels (SOVs);
- Crew Transfer Vessels (CTVs);
- Dredging vessels;
- Rock placement vessels;
- Accommodation vessels; and
- Multi-purpose support vessels.

It is expected that several vessels may work in parallel during the construction period. Conservative assumptions have been made on the vessel activities for the construction period and these are presented in Table 5-23. It is expected that upon detailed planning some vessels will be able to be shared between packages where possible. There will be a maximum of 30 vessels present at any one time.

Table 5-23 Estimated vessel requirements during the construction period

VESSEL TYPE	ESTIMATED MAXIMUM NUMBER	TRANSITS ACROSS ALL VESSELS
Accommodation Vessel or JUV Accommodation Vessel	2	10
SOV	5	60
Barge or Self Propelled Component Transport Vessel	24	203
Cable lay vessel	5	18
CTV	7	868
Dredging Vessel	4	N/A
Construction JUV	4	60
Small Support Vessel	8	96
Multipurpose Support Vessels	18	224
Ocean Going Tug	16	144
Rock Dumper	5	36
Semisubmersible Crane Vessel	3	3
TOTAL	101	1,722

Whilst most vessels will utilise Dynamic Positioning, and therefore, will not be in contact with the seabed, JUVs, which have a footing on the seabed, are being considered for the installation of the substructures for the WTGs and OSPs. It is anticipated that up to two jack-up events will be required per WTG and per OSP. In addition, anchored vessels may be utilised during the installation of the cables, assuming a six-point mooring system with 3 m^2 anchors deployed every 500 m of cable. The Project Design Envelope for the seabed footprint of these vessels is presented in Table 5-24.

Table 5-24 Design envelope for jack-up and anchored vessels

VESSEL	DESIGN PARAMETER	DESIGN ENVELOPE
JUV	Maximum number of JUV legs (per vessel)	6
	Maximum seabed footprint per JUV spud can (m^2)	270
	Maximum seabed footprint across the OWF (m^2)	421,200
Anchor vessel	Maximum seabed footprint (per anchor) (m^2)	3
	Maximum number of anchor drops[7]	Interconnector cables: 1,800 Inter-array cables: 6,000 Offshore export cables: 3,840
	Maximum seabed footprint (m^2)	34,920

Options for the construction assembly base are currently being considered and work has already been undertaken to assess Scottish port capabilities to understand the viability of options available to meet the Project requirements. Any additional works required at the ports under consideration are subject to their own planning, permitting and licensing requirements.

[7] *Assuming a six-point mooring system deployed every 500 m of cable*

5.10 Operations and maintenance

5.10.1 Operations and maintenance strategy

The operation and maintenance period will commence once the Project is commissioned. The operational life of the offshore Project is anticipated to be 30 years. During the operation and maintenance period, the offshore Project will operate with minimum day-to-day intervention. As described in section 5.5.1.1 and 5.6.1.2, the WTGs and OSPs will be controlled and monitored remotely via an onshore operation and maintenance base.

The overall operation and maintenance strategy will be finalised once the onshore operation and maintenance base location and technical specifications are known. An Operator will be appointed by the Project who will be responsible for the co-ordination and execution of the operation and maintenance activities, including Health and Safety and Environment management. The Operator will employ remote monitoring of the offshore Project, either from onshore operation and maintenance base or another location. Options for the onshore operation and maintenance base are currently being considered and work has already been undertaken to assess Scottish port capabilities to understand the viability of options available to meet the Project requirements. It is anticipated that the Project will be managed from a local onshore facility for the lifecycle of the Project. The key considerations for the selection of an operation and maintenance base include:

- Final design of the offshore Project;
- Vessels and associated logistical options; and
- Practical considerations such as local facilities and ease of access.

The onshore operation and maintenance base will likely comprise a port / harbour facility, with office, warehouse, welfare, storage and appropriate vessel facilities. The operation and maintenance base will be a point of access for many of the operation and maintenance monitoring or surveillance systems, and therefore, suitable communication links and technology will be established. The development of the operation and maintenance base is outwith the scope of this Offshore EIA Report.

An Operations and Maintenance Programme (OMP) will be produced post-consent which will outline the programme and timing of operation and maintenance activities.

5.10.2 Operation and maintenance activities

Each WTG will operate automatically with minimal intervention. A Supervisory Control and Data Acquisition (SCADA) computer system will monitor and control the output from each WTG.

Operation and maintenance activities will be undertaken with the intention of maintaining safety and optimizing yield and availability, in accordance with good wind industry practice, the Original Equipment Manufacturer (OEM) guidance and conforming to all appliable laws and regulations.

All offshore infrastructure, including WTGs, foundations, cables and OSPs will be included in monitoring and maintenance programmes.

The operation and maintenance activities associated with the various components of the offshore Project are provided in Table 5-25 .

Table 5-25 Operation and maintenance requirements

OPERATION AND MAINTENANCE ACTIVITIES	INDICATIVE FREQUENCY
WTGs	
• Scheduled / preventative maintenance: – Regular scheduled / preventative maintenance on all WTGs including, where applicable, statutory inspections and certification of certain equipment; and – Planned campaigns of work may require additional equipment or plant such as work platforms to assist with blade repair campaigns. • Minor faults and troubleshooting: correction of unplanned events (either remotely or through the attendance of technicians and/or trouble-shooters) when an unplanned loss of generation requires intervention or troubleshooting; and • Major component replacement: over the life of the asset it is anticipated that there will be a requirement for major component replacement including but not limited to replacement of gearbox, switchgear, blades, main bearing, transformer or generator.	• Annual routine inspections; and • Major maintenance will be ad hoc on discovery of a failure, or as part of a pre-emptive maintenance campaign.
Balance of Plant (BOP) and High Voltage infrastructure, including foundations, cables, OSPs and all ancillary equipment and infrastructure	
• Offshore Transmission Owner (OFTO) assets: – It is anticipated that there may be a period where the Project will be responsible for the maintenance of the OFTO assets prior to completion of the OFTO transaction. – The assets will be monitored remotely; and – Operation and maintenance activities will be carried out in accordance with original equipment manufacturer's manuals and will include routine inspection, testing and replacement of components; • BOP routine inspections: – Visual inspections, testing and survey work; and – Inspections will be undertaken on structural strength, lifting, climbing, safety equipment, corrosion and scour protection and cable protection systems;	• Annual routine inspections (eventually moving to three years for the cable assets); • Frequency of geophysical surveys will be dependent on the rate of any change on the seabed or the requirement for heavy lift vessels; and • Any significant maintenance and replacements will be ad hoc on discovery of a failure, or as part of a pre-emptive maintenance campaign.

OPERATION AND MAINTENANCE ACTIVITIES	INDICATIVE FREQUENCY
• BOP remedial or unscheduled maintenance: – More significant works can include repairs to grouted joints, rock placement to augment scour protection and intermittent repairs to secondary steelwork such as ladders, gates, grills and platforms; and – Other tasks can include the removal of marine growth, guano cleaning and painting of structures; • Geophysical surveys: – Ongoing surveys will be required throughout the life of the offshore Project to monitor cable location and seabed conditions. These surveys are generally conducted with specialist equipment from a CTV, with ROVs, Unmanned Surface Vessel (USVs); • Visual inspections of cable assets; and • Reactive cable repair, replacement and re-burial, as required, in the identification of a cable fault or in response to external factors (e.g. seabed mobility, erosion, third-party damage).	

5.10.3 Operation and maintenance vessel and helicopter requirements

Vessel and helicopter visits to the offshore Project will be required for routine and unscheduled maintenance and repair activities. Maintenance and repair activities are expected to be coordinated from the operation and maintenance base and personnel will be transported from the onshore operation and maintenance base to the offshore Project.

It is anticipated that routine maintenance will be serviced through SOVs, CTVs, daughter craft, ROVs, USVs, unmanned aerial vessels and helicopters. SOVs may remain on site for up to 14 days at a time and transfer of technicians and equipment would occur using a walk-to-work, motion compensated walkway. CTVs would be used for shorter routine and unscheduled maintenance trips, returning within a 12-hour period.

Major maintenance and repair activities, such as the replacement of large components, may require the use of JUV or semi-submersible crane vessels. It has been assumed that 5% of the WTGs will require major maintenance each year, with 14 transits anticipated annually.

The estimated vessel and helicopter requirements for the operation and maintenance period are presented in Table 5-26. It should be noted that the anticipated vessel and helicopter requirements during the operation and maintenance stage are indicative at this stage, as these are highly dependent on the final operation and maintenance strategy as well as the maintenance requirements, which are inherently uncertain. The Navigational Safety and Vessel Management Plan (NSVMP) (see OP4) and the OMP will provide further detail on vessel activity associated with the operation and maintenance period.

Table 5-26 Estimated vessel requirements during the operation and maintenance period

PARAMETER	REQUIREMENTS
Maximum number of annual helicopter trips	195
Maximum number of annual vessel trips	273
Maximum number of vessels present at the offshore Project at any one time	19

5.11 Repowering

If the decision is made to extend the offshore Project design life beyond what has been assessed within this Offshore EIA Report, this would be subject to a separate consenting process. Therefore, the repowering of the offshore Project beyond an operational period of 30 years is outwith the scope of this Offshore EIA Report.

5.12 Decommissioning

The Scottish Government's Decommissioning of Offshore Renewable Energy Installations in Scottish Waters (Scottish Government, 2022b) states that in order to minimise residual liabilities, retain value in Crown Estate Scotland assets, maximise seabed re-use and for the safety of other marine users, it is expected that all relevant objects will be fully removed at the end of their operational life. The Scottish ministers will consider exemptions from full removal only on presentation of compelling evidence that removal would create unacceptable risks to personnel or to the marine environment, be technically unfeasible or involve extreme costs. The preferred decommissioning option will be for as close to full removal as possible, whilst recognising that this will be subject to assessments and consultation closer to the time of decommissioning. This preference has been integral to the selection of design options and will continue to be through the detailed design stage.

The Energy Act 2004, as amended by the Scotland Act 2016 contains statutory requirements in relation to the decommissioning of Offshore Renewable Energy Installations (OREI) and require the offshore Project to provide a Decommissioning Programme, supported by details of the type and timing of appropriate financial security proposed. The Decommissioning Programme will follow the guidance found in the Scottish Government's Decommissioning of Offshore Renewable Energy Installations in Scottish Waters (Scottish Government, 2022b). Decommissioning activities will comply with all relevant legislation at that time and best practice at the time of decommissioning will be followed.

Throughout the offshore Project lifespan, the Decommissioning Programme will be reviewed and updated every five years. Consultee bodies listed in the S105 Notices, and any additional consultees identified by MD-LOT or OWPL will be provided with the opportunity to comment on the decommissioning strategy prior to it being finalised. It is anticipated that the final revision process will commence two years prior to the initiation of decommissioning activities. Best practice will be followed when developing a Decommissioning Programme.

Prior to the decommissioning of the offshore Project, the following activities are expected to occur:

- Thorough inspection of all infrastructure;
- De-energise and isolate the electrical systems from the national grid;
- Remove loose items and hazardous materials from structures;
- Installation of lifting points and lifting equipment;
- Cutting wiring at separation points e.g. between tower and nacelle; and
- Removal of fluids e.g. lubricants from the WTG.

This initial preparation stage allows works to be carried out from a smaller vessel, such as a personnel transfer vessel, maximising the efficiency of operations when the lift vessel required for removal of the WTG is brought on site. This stage is likely to require the use of standard tools, similar to those used during operation and maintenance stage.

The decommissioning approach for the various components of the offshore Project is provided in Table 5-27.

Table 5-27 Decommissioning approach

OFFSHORE INFRASTRUCTURE	DECOMMISSIONING APPROACH
WTGs and OSP topsides	It is expected that WTGs and OSP topsides will be removed in the reverse order of their installation using a JUV. The WTGs and OSPs will be disconnected from all electrical infrastructure, all hazardous materials and fluids will be removed, and the components will be transported to shore for reuse / recycling / disposal. WTGs can be dismantled in several configurations, using cutting tools such as plasma cutters and angle cutters to undo bolts and other connections. The rotor blades, nacelle and tower sections will likely be removed in that order. Once the WTGs are removed, they are transported back to shore. The OSP topsides will likely be removed as one piece using a semi-submersible crane vessel or crane barge. The OSP topsides would then be transported to an onshore facility for dismantling.
WTG and OSP foundations	Piled foundations will likely be cut below the seabed (typically at least 1 m below the seabed), using diamond wire cutting and abrasive water jet cutting either internally or externally, and the sections above will be removed. Removal of the entire pile is not considered necessary and would result in disproportionate environmental impacts. However, this would be confirmed through consultation and assessment to ensure the most suitable approach was taken. This operation will utilise a JUV or semi-submersible crane vessel. Before the foundations can be removed, the J-tubes, cable connections and other external structures will be detached. Depending on the combined weight of the substructure and transition piece both pieces may be removed as a single lift or detached and removed separately. For suction bucket foundations, the suction buckets can be removed through a controlled pump system to apply pressure to release the suction buckets which can then be extracted from the seabed. Scour protection may be left *in situ* to preserve the marine habitat that has established over the life of the offshore Project. However, it is recognised that there is a preference for as close to full removal of all infrastructure as possible. If removal of scour protection is deemed

OFFSHORE INFRASTRUCTURE	DECOMMISSIONING APPROACH
	necessary, it is expected to be dredged and transported to be re-used or disposed of at a licensed disposal area (this could be offshore or onshore).
Cables	The decommissioning options for the cables will be discussed with stakeholders and regulators, however, sections of the cable may likely be left *in situ* to avoid unnecessarily disturbing the seabed particularly where rock protection has been used and marine habitat has been formed. This would be confirmed through consultation and assessment to ensure the most suitable approach was taken. For decommissioning *in situ*, the cable ends are located and buried at an acceptable depth below the seabed. This is likely to require the use of a ROV equipped with suitable trenching and burial equipment and accompanying support vessel. It is assumed that to decommission the cables in situ the cable is already buried along its length and so limited activity is required along the length of the cable. Exposed sections of cable will most likely be cut and removed or subjected to rock placement to ensure they are over trawlable.
Decommissioning vessels and helicopters	As decommissioning is expected to be a reverse of construction, the same maximum development scenario vessel requirements apply, as described in section 5.9.1.
Seabed clear and post-decommissioning monitoring and management	Surveys will be undertaken following decommissioning to ensure the offshore Project is safely and effectively decommissioned. These will be in accordance with the Decommissioning Programme and agreed with consultees. If any infrastructure is left *in situ*, then it may be monitored and managed, and the requirement for this will be confirmed with consultees. This will depend on the extent of infrastructure left *in situ*, and hence, the risk posed to other marine users. If any hazards are identified these will be marked and remediated as required.

5.13 Safety zones

Statutory and advisory safety zones[8] may be utilised during the various stages of the offshore Project. The safety zone requirements across the construction, operation and maintenance and decommissioning stages are summarised in Table 5-28.

[8] *Statutory safety zones cannot be established around vessels themselves. It is standard safe working practice to establish advisory minimum safe passing distances around areas of vessel activity that present a navigational safety risk to marine users. These advisory safety zones are generally 500 m and move with the vessel during its operation.*

Table 5-28 Safety zone requirements across all stages of the offshore Project

STAGE	SAFETY ZONE REQUIREMENT
Construction	During the construction period, it is expected that a statutory 500 m safety zone around the outer edge of the proposed WTG and OSP locations will be applied for under Section 95 of the Energy Act 2004 and in accordance with Schedule 16 of the Energy Act 2004 and the Electricity (Offshore Generating Stations) (Safety Zones) (Application Procedures and Control of Access) Regulations 2007. The statutory 500 m safety zone will be in operation where construction work is underway and while Restricted in Ability to Manoeuvre (RAM) vessels are present. The statutory safety zones will be implemented on a 'rolling' basis, meaning that the 500 m statutory safety zones will be phased throughout the OAA. Therefore, when construction is completed at one location, the 500 m statutory safety zone will be lifted, and a subsequent 500 m statutory safety zone will be placed around the next construction location. The safety zones will be reduced to 50 m around any WTG or OSP where construction work is not underway, and around any completed structure prior to commissioning. This is intended to reduce the extent of the area from which vessels will be excluded during construction and decommissioning. Statutory safety zones cannot be established around vessels themselves. However, it is standard safe working practice to establish advisory minimum safe passing distances around areas of vessel activity that present a navigational safety risk to marine users. These advisory safety zones are generally 500 m and move with the vessel during its operation.
Operation and maintenance	During times of major maintenance works, a temporary 500 m statutory safety zone may be applied for under the Electricity (Offshore Generating Stations) (Safety Zones) (Application Procedures and Control of Access) Regulations 2007.
Decommissioning	During decommissioning, safety zones may also be required, and this will be determined at a later stage when decommissioning plans are known. It is expected that safety zones will be applied for in a similar manner to the construction stage.

5.14 Onshore infrastructure

5.14.1 Overview

Planning permission is being sought under the Town and Country Planning (Scotland) Act 1997 for the onshore Project and this is subject to a separate consenting process and a separate onshore EIA. Information on the onshore Project is included here to ensure a complete understanding of the whole Project. The onshore Project will comprise:

- Landfall infrastructure landward of MLWS at Greeny Geo and/or Crosskirk, Caithness;
- Up to five TJBs at one or across both landfall;
- Up to five underground onshore export cables, comprising 15 power cables and five communication cables in total, which transmit power as HVAC, underground between the TJBs and the onshore substation;
- One new onshore substation at Spittal;

- Temporary compounds during construction of the onshore substation, TJBs and installation of onshore export cables;
- Temporary haul road and access tracks during construction; and
- Seven permanent (indicative at this stage) access tracks (indicative at this stage) across the onshore Project area.

5.14.2 Construction

It is anticipated that the construction of the onshore elements of the Project will take approximately four years (subject to change). The general series of activities is outlined below Table 5-29.

Table 5-29 Outline of onshore construction activities

ACTIVITY	DESCRIPTION
Project-specific surveys and site investigations	Project specific surveys and site investigations may be undertaken, potentially including intrusive archaeological investigations, ecology surveys, hydrology surveys, geotechnical and ground stability surveys. The requirement for these surveys will be determined following the engineering design phase and through the consent conditions.
Landfall works	The landfall works will involve the following activities: • Setting up of a temporary construction site, HDD compound and access tracks for the landfall works; • HDD for landfall installation; • Laying of ducts for later installation of cables; • Construction of TJBs; • Installation and jointing works of onshore and offshore cables to TJBs; and • Reinstatement, where necessary.
Cable enabling works	The cable enabling works will be carried out ahead of cable installation and may involve site preparation, including topsoil stripping and fencing off of construction areas, setting up of temporary work areas, providing main utilities (electrics, water and telecommunications) to service the site and construction of haul roads.
Cable route installation	Following the enabling works, infrastructure to accommodate underground cables will be constructed. The primary method is expected to be open-cut trenching which will involve the excavation of trenches along the cable route. Ducts will be installed, and the habitat reinstated. Construction of Cable Joint Bays (CJBs) are expected alongside the installation of the ducts. Due to the ground conditions present along the onshore export cable corridor, there is potential that rock breaking, battered-back or shore excavations in glacial tills, dewatering systems and shoring in wetter ground condition may be required. After CJBs construction, the onshore cable would be pulled through the ducts. Trenchless crossings will be used to avoid disturbance to sensitive surface features or when crossing linear features (e.g. railway lines and major river crossings).

ACTIVITY	DESCRIPTION
Onshore substation enabling works	The substation enabling works will involve the following stages: • Site preparation, earth works (including topsoil stripping, site clearance, and commencement of bund construction), fencing off of the construction areas, provision of services to the site, creation of temporary works; and • Construction of temporary and permanent access roads and compounds.
Onshore substation civil and electrical works	Following the enabling works, the substation civil and electrical works will commence, which will comprise the following stages: • Civil works to prepare the site for the heavy-duty equipment required for the installation of the foundations and buildings. This will comprise earthworks to create a firm and level platform across the site and bunds creation; • Foundation concrete works for the main electrical components and buildings which may comprise piled and/or shallow foundations; • Construction / installation of the main buildings; • Installation and testing of electrical equipment; • Landscaping works including earthworks / bund landscaping and vegetation planting; and • Commissioning activities.
Temporary and permanent access - cables	Maximum of 650 m temporary access tracks required during cable installation. Seven permanent access tracks comprising approximately 5 km to provide access to landfall(s), crossings and substation comprising. This will be a combination of existing tracks (1.2 km), existing tracks that require improvements (2.21 km) and newly installed tracks (1.67 km).
Temporary and permanent access - substation	Temporary access roads required during construction (1 km). Permanent access road for operation and maintenance (600 m).

5.14.3 Operation and maintenance

Following commissioning, it is assumed that the onshore substation will operate continuously (24 hours a day, seven days a week) except during planned shutdowns for maintenance. The onshore substation will be designed to remain *in situ* during the lifetime of the onshore Project.

There will be a limited amount of traffic to and from the onshore substation for general operation and maintenance purposes. Beside this, there will be no day-to-day personnel on site in normal operation. Unexpected faults may lead to increasing traffic volumes depending on the type of fault.

Activities on the underground cable system during the operation and maintenance stage will include:

- Regular and ad-hoc visits: including activities for inspection / maintenance purposes; and
- Non-routine activities: including activities to repair of damage to cable or replacement of failed cable joint, or faults / failures of key plant items at the onshore substation.

5.14.4 Decommissioning

A Decommissioning Restoration and Aftercare Plan will be required as a planning condition to be approved by the regulator, prior to the onshore decommissioning works. Decommissioning best practice and legislation will be applied at that time. It is expected that decommissioning will follow a reverse order of the installation activities with some infrastructure potentially left *in situ*.

5.15 Consideration of hazards, accidents and risks

5.15.1 Major accidents and hazards

The EIA regulations (as defined in chapter 3: Planning policy and legislative context) require the EIA to consider any "*expected effects deriving from the vulnerability of the works to risks, so far as relevant to the works, of major accidents and disasters*". The EIA regulations go on further to state that the Offshore EIA Report should include "*A description of the expected significant adverse effects of the development on the environment deriving from the vulnerability of the development to risks of major accidents and/or disasters which are relevant to the project concerned. Relevant information available and obtained through risk assessments pursuant to EU law such as any law that implemented Directive 2012/18/EU of the European Parliament and of the Council or Council Directive 2009/71/Euratom or UK environmental assessments may be used for this purpose provided that the requirements of any law that implemented this Directive are met. Where appropriate, this description should include measures envisaged to prevent or mitigate the significant adverse effects of such events on the environment and details of the preparedness for and proposed response to such emergencies.*"

As described in the Institute of Environmental Management and Assessment (IEMA) (2020) 'Major Accidents and Disasters in EIA: A Primer guidance', major accidents refer to low likelihood high consequence events that threaten immediate or delayed serious environmental effects to human health, welfare and/or the environment and requires the use of resources beyond those of the client or its appointed representatives (i.e. contractors) to manage.

The offshore Project has been designed to operate within the marine environment and relevant extreme environmental conditions (e.g. storm events) for the lifetime of the offshore Project have been considered in the Project Design Envelope. The offshore Project will not include any large inventories of hazardous material that could be released in the event of a natural disaster.

Relevant aspects of the Offshore EIA Report have considered the risk of environmental disasters to the offshore Project and the associated risks to the environment and society. SS2: Major accidents and disasters summarises the risk assessment that was undertaken for relevant hazards identified which had a potential to cause a major accident or disaster, to understand the potential for a significant adverse effect on the environment, human health or material assets. The assessment references relevant topic specific assessments and the Construction Design Management Risk

Register[9] to assign a risk consequence and likelihood. All risks were considered to be at an acceptable level with the implementation of embedded mitigation measures and no additional mitigation has been identified. Risk reduction will continue to be refined during detailed engineering design, to ensure that a hierarchy of controls are in place through the various management plans and method statements.

5.15.2 Climate hazards and risks

Similar to the consideration of major accidents and hazards, the EIA regulations require that that the impact of the offshore Project on climate, and the vulnerability of the offshore Project to climate change, are assessed. This has been included in SS1: Climate and carbon assessment.

The carbon assessment produced for the Project (covering both the onshore and offshore Project) is also provided in SS1: Climate and carbon assessment.

Under the worst case scenario, the majority of the Carbon dioxide equivalent (CO_2e) emissions are associated with the construction stage (embodied carbon and construction vessel activity) and CO_2e emissions during the operation and maintenance stage are comparatively low. The impact of the Project on the UK carbon budget is assessed as negligible, and therefore, the Project will not affect the UK Government's ability to meet any individual carbon budget. Overall, the carbon assessment concluded that the Project would make a significant beneficial contribution to the UK carbon budget through the avoidance of more carbon-intensive energy sources. The payback period, defined as the period of time before the Project has avoided more carbon emissions than has been produced by its construction and operation, is estimated to be 8 years.

The vulnerability of the offshore Project to climate change is considered in the assessment of climate resilience in SS1: Climate and carbon assessment. This assessment considers the ability for the offshore Project to withstand projected changes in climate variables that could present a climate hazard or risk (e.g. projected changes in wave height and frequency of storms). Overall, the level of risk associated with climate hazards is assessed as minor or negligible for all projected changes in climate variables. The offshore Project has been adequately designed to withstand future climate projections, extrapolated over the lifetime of the offshore Project. Therefore, the offshore Project is considered to be resilient to climate change across the operation and maintenance stage.

It should be noted that although the confidence in future climate projections is increasing, there are still data uncertainties and this is a growing area of research. The assessment has been carried out using the most comprehensive and up-to-date data sources, however, it is acknowledged that the assessment of climate resilience is limited by the data available at the time of the assessment.

[9] *The Construction Design Management risk register is a live document produced to identify, assess, and control potential hazards and risks, in line with the Construction (Design and Management) Regulations 2015.*

5.16 Embedded mitigation

Embedded mitigation measures are measures that reduce the potential for impacts to the environment. Embedded mitigation can take different forms, but primary mitigation measures are those that are identified and adopted as part of the evolution of the design for the offshore Project. As described in chapter 7: EIA methodology, primary mitigation refers to measures built into the design of the offshore Project. The primary measures for the offshore Project are summarised in Table 5-30. Other forms of mitigation, including secondary and tertiary mitigation do not form part of the fundamental design of the offshore Project and are highlighted within each topic specific chapter.

Relevant mitigation measures (including primary, secondary and tertiary) and management plans for each EIA topic are detailed in the topic-specific EIA chapters (chapters 8 – 20), and a full list of the mitigation measures are provided within chapter 22: Summary of mitigation and monitoring.

The Sectoral Marine Plan (SMP) for Offshore Wind identified development areas for offshore wind around Scotland. The marine planning process that informed the SMP took account of some key environmental constraints and went some way in mitigating environmental impacts. Specifically for the N1 Plan Option (PO), this included avoidance of shipping and navigational constraints, aviation and other sea user receptors and designated sites.

Table 5-30 Embedded primary mitigation measures

EMBEDDED MITIGATION	FORM	DESCRIPTION
Site selection	Primary	Over and above the SMP site selection process, the offshore Project, including the OAA and offshore ECC, avoids or minimises any overlap with designated sites (e.g. the North West Orkney Nature Conservation Marine Protection Area (NCMPA) and to avoid the Food and Environment Protection Act (FEPA) Order Zone, the Yankee Main Helicopter Route and the sightlines between Scotland and Orkney.
Consideration of environmental constraints for final layout	Primary	Consideration of benthic ecology features as part of the constraints mapping exercise, and subsequent micro-siting exercises, to inform final locations of WTGs and associated offshore infrastructure including inter-array cables and offshore export cable routes. The final offshore Project layout will be presented within the Development Specification and Layout Plan (DSLP) and CaP. In addition, the fishing industry has been consulted through the Fisheries Working Group on the proposed offshore ECC. The fishing industry will continue to be consulted on the final WTG layout and cable routes and design through the Fisheries Working Group (or equivalent post consent). Where anthropogenic geophysical anomalies are identified in any subsequent marine geophysical survey, seabed preparation, device locations, cable routing and installation activities will avoid these by a minimum of 30 m.
Scour protection	Primary	The use of scour protection around the foundations of WTGs and OSPs will minimise scour effects around infrastructure. However, scour protection will only be implemented where required and will be minimised as far as is practicable. This will be informed by a scour assessment, undertaken post-consent.
Cable protection	Primary	Suitable implementation and monitoring of cable protection (via burial or external protection). Cables will be buried as the first choice of protection. External cable protection will be used where adequate burial cannot be achieved and this will be minimised as far as is practicable. This will be informed by a CBRA undertaken post consent following results of the geotechnical survey.

EMBEDDED MITIGATION	FORM	DESCRIPTION
Landfall installation methodology	Primary	Landfall installation methodology (Horizontal Directional Drilling, HDD) will avoid direct impacts to the intertidal area, including at the mouth of the River Forss.
Pre-construction cable route surveys	Primary	Pre-construction cable route survey to confirm the state of the seabed and that no significant changes have occurred from previous surveys, confirm the presence of morphological features and the requirement for micro-siting around these or completion of seabed preparation works. The final offshore Project layout will be presented within the DSLP and CaP.
WTG and Offshore Substation Platform OSP design	Primary	The WTG and OSP topsides are designed and constructed to contain leaks, thereby reducing the risk of spillage into the marine environment. Details on control measures for reducing the risk of accidental leaks and spills will be detailed within the Marine Pollution and Contingency Plan (MPCP) (see OP1: Outline Environmental Management Plan which contains the outline MPCP).
Detonation of UXO using low order techniques	Primary	Low order techniques for UXO detonation will be utilised wherever practicable to reduce underwater noise effects.
Lighting and marking as appropriate for the final agreed layout	Primary	Excess lighting, above levels set by regulatory requirements for navigation, aviation, escape/emergency procedures and general activity, will be avoided wherever possible. External general lighting will use timers and/or PIR devices to reduce excessive lighting of the turbines and OSPs. Marking and lighting of the site in agreement with NLB and in line with IALA Guideline G1162 and Recommendation O-139 (IALA, 2021). Furthermore, the Lighting and Marking Plan (LMP) will set out specific requirements in terms of aviation lighting to be installed on the wind turbines, as required under Civil Aviation Authority (CAA). Civil Aviation Publication (CAP) 393, Air Navigation: The Order and the Regulations (2016). The LMP will be prepared in consultation with the CAA, Ministry of Defence (MoD) and MCA and will take into account requirements for aviation lighting as specified in Article 223 of the UK Air Navigation Order 2016 and changes to ICAO Annex 14 Volume 2, Chapter 6, paragraph 6.2.4 promulgated in November 2016. An outline LMP is provided as part of the offshore application in OP6: Outline Lighting and Marking Plan.

EMBEDDED MITIGATION	FORM	DESCRIPTION
The use of guard vessels and Offshore Fisheries Liaison Officers (OFLO), where required	Primary	The use of guard vessels and OFLOs, where appropriate. Where possible, these will be sourced locally and /or will be Scottish.
Application for and implementation of safety zones	Primary	Application for safety zones of up to 500 m around structures during construction and periods of major maintenance, and 50 m around structures pre-commissioning.
Buoyed construction area	Primary	Buoyage to mark construction area of the OAA during the construction stage, as directed by NLB. The buoys will alert vessels to the construction area, they will not act to exclude vessels from the area.
Marine coordination	Primary	Marine coordination and communication to manage Project vessel movements.
Minimum blade clearance	Primary	Blade clearance of 27.05 m above MSL (29.52 m above LAT),which is in excess of the minimum requirement of 22 m above MHWS.
Project vessel Automatic Identification System (AIS) transmission	Primary	All project vessels will broadcast via AIS.
Minimum spacing between WTGs	Primary	The minimum spacing between WTGs will be 944 m.

5.17 Variances from the Project Design Envelope presented in the Scoping Report

The design details of the Project are being refined throughout the development stage. The Project description described above has some variances in dimensions and measurements from those provided in the Scoping Report, which was prepared based on the best design information available at that time. Where the worst case scenario dimensions and measurements differ from those that were presented in the Scoping Report, they are set out in Table 5-31 including explanatory notes as to the reason for the variance.

Consideration has been given as to whether in the case of any variance, the scoping advice from consenting authorities and stakeholders would have differed had the updated dimensions or measurements been available at the time of scoping. This is not considered to be likely.

Table 5-31 Variation in design parameter since EIA Scoping

DESIGN PARAMETER	DETAILS PRESENTED IN SCOPING REPORT	PROJECT DETAILS AT TIME OF EIA	REASON FOR DIFFERENCE IN PARAMETERS
WTG spacing	Minimum spacing 1 km	Minimum spacing 944 m	More precise spacing distances based on refined engineering calculations since scoping.
WTG foundations	Jacket dimensions at the seabed 35 m x 35 m	Jacket dimensions at the seabed 41 m x 41 m	Need to ensure the EIA assesses foundation sizes associated with the largest potential WTGs, therefore allowing for WTG technology evolution ahead of construction. No WTGs this large had been assessed before and therefore it was not possible to source data on the possible foundation dimensions without supplier engagement. It was not possible to engage with WTG suppliers at the scoping stage, the Project has since, which has informed the parameters presented and assessed in the Offshore EIA Report. The Project also now has more knowledge of the metocean and bathymetry conditions across the OAA which influences these design parameters.
	Suction bucket diameter 12 m	Suction bucket diameter 13 m	
	Suction bucket penetration depth 15 m	Suction bucket penetration depth 30 m	
OSPs	Topside dimensions (width and length) 45 m x 38 m	Topside dimensions (width and length) 45 m x 66 m	Need to ensure the EIA assesses OSP sizes associated with the largest possible OSP. Dimensions associated with a larger number of smaller OSPs will be less than those associated with a smaller number of larger OSPs. The number of OSPs will be up to five and should five OSPs be required their dimensions will be within those presented in the Scoping Report. It was not possible to engage with the supply chain at the scoping stage, however the Project has since, which has informed the parameters presented and assessed in the Offshore EIA Report associated with the largest possible OSP (of which only 3 would be required). The Project also now has more knowledge of the metocean and bathymetry conditions across the OAA which influences these design parameters. There has been an increase in some OSP foundations parameters which is due to the increase in the largest OSP topside dimensions.
	Base dimensions 35 x 35 m	Base dimensions 63 x 63 m	
	Up to 8 piles per foundation	Up to 16 piles per foundation	
	Suction bucket jacket foundation not included	Suction bucket foundation included, with diameter of 8 m	
Cables	Inter-array cable voltage 132 kV	Inter-array cable voltage 145 kV	The cable specification has not changed since scoping. The voltage presented in the Scoping Report was operational voltage, whereas the voltage presented in the EIA Report is rated voltage.
	External cable diameter of inter-array cables 225 mm	External cable diameter of inter-array cables 240 mm	These slight difference in dimensions are due to engineering refinement that has taken place since scoping and information that has been made available from supplier engagement.

DESIGN PARAMETER	DETAILS PRESENTED IN SCOPING REPORT	PROJECT DETAILS AT TIME OF EIA	REASON FOR DIFFERENCE IN PARAMETERS
	Inter-array cable trench width 2 m	Inter-array cable trench width 5 m	
	Installation tool up to 15 m width (inter-array cables)	Disturbance (seabed) width from installation tool 50 m (inter-array cables)	Details on the disturbance area associated with the installation tool has only been made available via supplier engagement since scoping.
	Inter-array and offshore export cable target burial depth 1-3 m	Inter-array and offshore export cable target burial depth 1-3 m, but maximum depth 5 m	The target burial depth remains unchanged from the Scoping Report, however engineering refinement since scoping has indicated there may be a need to go deeper in specific circumstances e.g. sandwave areas.

5.18 References

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5.19 Abbreviations

ACRONYM	DEFINITION
AIS	Automatic Identification System
B	Magnetic components
BOP	Balance of Plant
BWM	Ballast Water Management
CAA	Civil Aviation Authority
CaP	Cable Plan
CBRA	Cable Burial Risk Assessment
Cefas	Centre for Environment, Fisheries and Aquaculture Science
CfD	Contract for Difference
CFE	Controlled Flow Excavator
CJB	Cable Joint Bay
COLREGS	International Regulations for the Prevention of Collision at Sea
CO_2e	Carbon dioxide equivalent
CPS	Cable Protection System
CSV	Construction support vessels
CTV	Crew Transfer Vessel
cUXO	Confirmed Unexploded Ordnance
DBA	Desk Based Assessment

ACRONYM	DEFINITION
DECC	Department of Energy and Climate Change
DGC	Defence Geographic Centre
DSLP	Development Specification and Layout Plan
E	Electric
ECC	Export Cable Corridor
EIA	Environmental Impact Assessment
EMF	Electromagnetic Fields
EPS	European Protected Species
ERCoP	Emergency Response Cooperation Plan
EU	European Union
FEPA	Food and Environment Protection Act
FIR	Fisheries Industry Representative
FLO	Fisheries Liaison Officer
FMMS	Fisheries Management and Mitigation Strategy
G^3	Green Gas for Grid
HDD	Horizontal Directional Drilling
HO	High Order
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current

ACRONYM	DEFINITION
IAIP	Integrated Aeronautical Information Package
IALA	International Association of Marine Aids to Navigation and Lighthouse Authorities
iE	induced Electric
IMO	International Maritime Organisation
INNS	Invasive Non-Native Species
IPS	Intermediate Peripheral Structures
JUV	Jack Up Vessel
km	Kilometre
kJ	Kilojoule
LAT	Lowest Astronomical Tide
LCoE	Levelised Cost of Energy
LCM	Lost Circulation Material
LMP	Lighting and Marking Plan
LO	Low Order
m	Metre
m^2	Metres squared
m^3	Metres cubed
MARPOL	International Convention for the Prevention of Pollution from Ships
MBES	Multi-Beam Echo Sounder

ACRONYM	DEFINITION
MCA	Maritime and Coastguard Agency
MD-LOT	Marine Directorate - Licensing Operations Team
MGN	Marine Guidance Note
MHWS	Mean High Water Springs
MoD	Ministry of Defence
MPCP	Marine Pollution Contingency Plan
MSL	Mean Sea Level
MS-LOT	Marine Scotland - Licensing Operations Team
MW	Megawatt
NCMPA	Nature Conservation Marine Protection Area
NLB	Northern Lighthouse Board
nm	Nautical mile
NOTAM	Notice to Airmen
NSP	Navigational Safety Plan
NtM	Notice to Mariner
OAA	Option Agreement Area
OCT	Open Cut Trench
OEM	Original equipment manufacturer
OFLO	Offshore Fisheries Liaison Officer

ACRONYM	DEFINITION
OFTO	Offshore Transmission Owner
OIC	Orkney Island Council
OMP	Operation and Maintenance Programme
OREI	Offshore Renewable Energy Installation
OSP	Offshore Substation Platforms
OWF	Offshore windfarm
OWPL	Offshore Wind Power Limited
PAD	Protocol for Accidental Discoveries
PEMP	Project Environmental Monitoring Programme
PLGR	Pre-Lay Grapnel Run
PO	Plan Option
pUXO	Potential Unexploded Ordnance
RAL	Reichs-Ausschuss für Lieferbedingungen und Gütesicherung
RAM	Restricted in Ability Manoeuvre
ROV	Remotely Operated Vehicle
ROVSV	Remote operated vehicle support vessels
SAR	Search and Rescue
SBP	Sub-Bottom Profiler
SCADA	Supervisory Control and Data Acquisition

ACRONYM	DEFINITION
SF_6	Sulphur hexafluoride
SHET-L	Scottish Hydro Electric Transmission Ltd plc
SMP	Sectoral Marine Plan
SOLAS	International Regulations for the Safety of Life at Sea
SOPEP	Shipboard Oil Pollution Emergency Plan
SOV	Service Operation Vessel
SPS	Significant Peripheral Structures
SSS	Side-Scan Sonar
THC	The Highland Council
TJB	Transition Joint Bay
TSHD	Trailing Suction Hopper Dredge
UK	United Kingdom
UKHO	UK Hydrographic Office
USBL	Ultra Short Baseline
USV	Unmanned Surface Vessel
UXO	Unexploded Ordnance
µT	Micro tesla
$V\ m^{-1}$	Volts per metre
VMP	Vessel Management Plan

ACRONYM	DEFINITION
WSI	Written Scheme of Investigation
WTG	Wind Turbine Generator
°C	Degrees Celsius